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Assessment of SO2 and NOx Emission Control Technology in Europe

Ellison Consultants, Monrovia, MD

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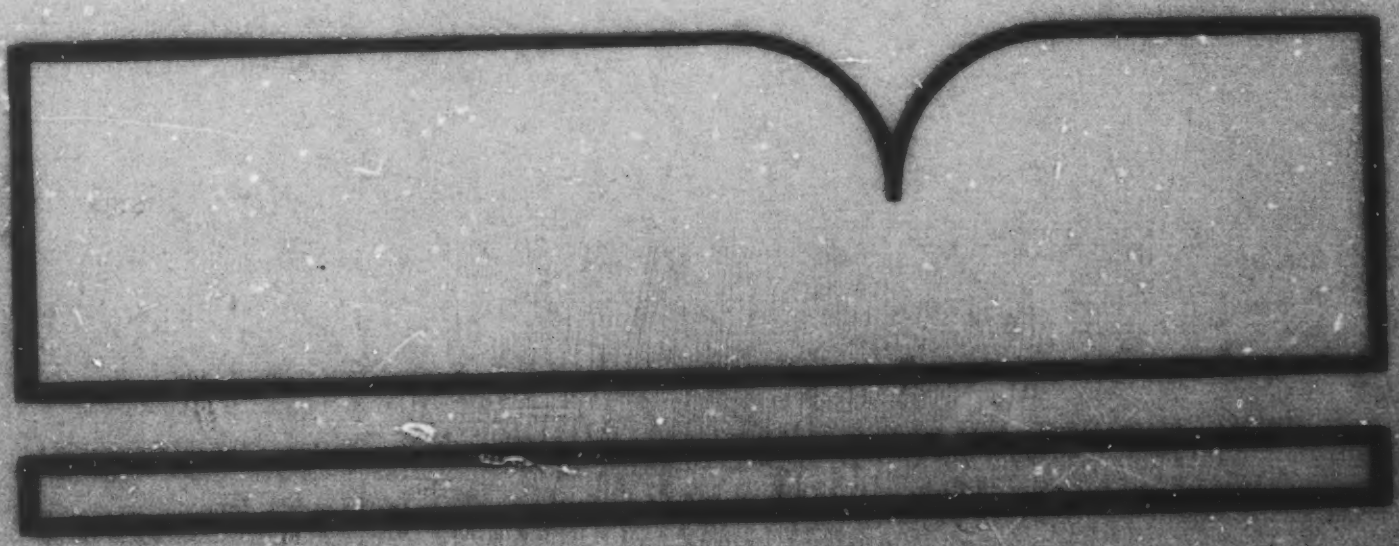

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FOREWORD

This report presents information on the current status and costs of air pollution control technology used in Europe. Included are reported costs of air pollution control systems installed at West German facilities. Caution should be used in attempting to compare the costs of U.S. control systems with German control systems because the design and economic bases are different. Differences in fuel properties, regulatory requirements, cost of capital, labor, etc. make such comparisons difficult and not meaningful. For this reason, control technology costs presented in this report are in 1986 Deutschmarks. If the reader wishes to convert the reported costs to a dollar basis, he/she should do so with caution. Although the costs contained in this document are not directly related to the U.S. experience, they are useful in illustrating the relative cost differentials between different emission control concepts and between variations of a given concept.

ABSTRACT

This report is a compilation of information on the current status of abatement technology used to control major air pollutants, including SO_2 and NO_x, in Europe. It focuses on flue gas desulfurization (FGD), combustion modification (CM), and selective catalytic reduction (SCR) of NO_x. Information presented in this report was gathered from utility company representatives and FGD, CM, and SCR process developers, as well as from the author's research in this field. Current air pollution regulations in Europe, related problems, operational parameters of commercial FGD and SCR plants, FGD and SCR economics, and the author's evaluation of the processes also are described.

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LIST OF ABBREVIATIONS AND SYMBOLS

AC	activated carbon
AG	incorporated
AH	air heater
A/P	air preheater
B	burner
$CaCO_3$	calcium carbonate
$CaSO_4$	calcium sulfate
°C	degrees Centigrade
CEGB	Central Electric Generating Board (UK)
CFB	circulating fluid bed
CITEPA	Centre Interprofessionnel Technique D'Etudes de la Pollution Atmospherique (France)
CM	combustion modification
DB	Deutsche Babcock
$deNO_x$	nitrogen oxides removal
DKEG	Steam Boiler Emissions Law (Austria)
DN	$deNO_x$
DNCAP	$deNO_x$ compatible air preheater
DNAP	$deNO_x$ air preheater
DNC	$deNO_x$ compatible
(e)	electric
EEC	European Economic Community
ENEL	Italian National Power Company
EP	electrostatic precipitator
EPRI	Electric Power Research Institute
°F	degrees Fahrenheit
FeEDTA	ferrous ethylene-ditoluene-tetraacetate
FF	fabric filter
FGD	flue gas desulfurization
FGR	flue gas recirculation
GEA	GEA Kuehlturmbau und Luftcondensation GmbH
g	gram
GEESI	General Electric Environmental Services Inc.
GFAVO	ordinance governing large furnace installations (West Germany)
GGH	gas-gas heat exchanger
GJ	gigajoule
GmbH	incorporated
GRP	glass reinforced plastic
h, Hr	hour
H_2O	water
HC	hydrocarbon
HCl	hydrogen chloride
HCN	hydrogen cyanide
H_2SO_4	sulfuric acid
ID	induced draft
IFNR	in furnace NO_x reduction
IHI	Ishikawajima-Harima Heavy Industries
in.W.G.	inches of water gauge

ISPRA, Ispra	city in Italy
KEMA	Institute for testing electrical materials (The Netherlands)
kg	kilogram
kV	Kilovolt
kW	kilowatt
kWh	kilowatt hour
l	liter
Lb, lb	pound
LI	lime/limestone injection
LIMB	lime/limestone injection into a multistage burner
m	meter
m^3	cubic meter
mA	milliampere
mbar	millibar
mg	milligram
MJ	megajoule
mm	millimeter
MM	million
MMBtu	million British thermal units
MMDM	million German marks
MW	megawatt
N_2	nitrogen
NH_3	ammonia
$(NH_4)_2SO_4$	ammonium sulfate
$(NH_4)HSO_4$	ammonium bisulfate
NHi	formula of nitrogen-hydrogen combustion products with i equal to a variable integer
Nm^3	normal cubic meter (0°C, 1 atmosphere pressure)
No.	number
NO	nitric oxide
NO_x	nitrogen oxides
NO_2	nitrogen dioxide
O_2	oxygen
Oxid.	oxidation
PDU	process development unit
Pfg.	German pfennig, 1/100 of a mark
pH	potential of hydrogen
ppm	parts per million by volume
PTFE	polytetrafluor ethylene (Teflon)
PVDF	polyvinylidene fluoride (Kynar)
REG.	regenerator
S	sulfur
SCR	selective catalytic reduction
SHL	Saarberg-Hoelter-Lurgi
SK	Swedish crown (kroner)
SNCR	selective noncatalytic reduction

LIST OF ABBREVIATIONS AND SYMBOLS (Continued)

SO_x	sulfur oxides
SO_2	sulfur dioxide
SO_3	sulfur trioxide
(t)	thermal
t or ton	metric ton
TA Luft	air pollution control regulations (West Germany)
TiO_2	titanium dioxide
UK	United Kingdom
VGB	VGB Technical Association of Large Power Plant Operators (Europe)
V205	vanadium pentoxide
WA	heat exchanger for reheating
WT	heat exchanger for reheating

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EXECUTIVE SUMMARY

The very strong reaction of the government of the Federal Republic of Germany (West Germany) in 1983 to mounting indications of accelerated forest dieback attributable to air contaminants has led to massive expenditures in that and other European countries for retrofit installation of flue gas desulfurization (FGD), i.e. scrubbers, on coal-burning steam boilers. In most instances coal sulfur content is low to medium, and substantially lower than coal sulfur levels in bituminous coal used for boiler fuel in eastern and midwestern U.S.A. 1983 West German legislation (GFAVO) calls for retrofitting by 1988 of FGD facilities of a minimum of 85% sulfur dioxide (SO_2) removal efficiency, with stack emission no greater than 400 milligrams (mg) per normal cubic meter (Nm^3) of flue gas, for new and existing boilers greater than approximately 110 megawatts, i.e. MW(e), size. As of 1986, more than 100 FGD systems with greater than 40,000 MW(e) aggregate capacity have been purchased in West Germany alone, more than 93% of it of the form of usable-gypsum-producing wet lime/limestone scrubbing comparable to many such facilities in Japan and to a number of such flue gas cleaning systems installed in the U.S.A. beginning in the late 1970s. Other important FGD technologies are also being utilized in West Germany, some of them of potential value in any future retrofit high-sulfur FGD applications in the U.S.A.

1983 West German legislation requires by 1993 the retrofit addition of approximately 400 more FGD installations aggregating approximately 25,000 MW(e) of capacity on boilers in the size range 35 to 110 MW(e). Land availability in mainland European countries is such that it is generally necessary to apply usable-byproduct-forming FGD systems to avoid need for throwaway disposal of FGD solid waste. In view of the many millions of annual metric tons of synthetic gypsum supply that could ultimately be created, and some uncertainty as to the magnitude of available markets for this material, FGD technologies other than lime/limestone-gypsum scrubbing are expected to be given serious consideration in achieving compliance with the 1993 SO_2 control deadline.

Stringent West German SO_2 legislation in 1983 was followed in 1984 by enactment of very stringent new nitrogen oxides (NO_x) limits calling for emissions of no more than 200 mg NO_x, measured as nitrogen dioxide, NO_2, per Nm^3, approximately 0.16 lb NO_2 per million Btu heat input, for existing and new boilers greater than 110 MW(e), size. As of 1986 approximately 50 high-efficiency commercial systems aggregating more than 10,000 MW(e) capacity, most for retrofit addition, have been purchased in West Germany alone, and approximately 30,000 MW(e) of additional NO_x removal capacity will be required to be retrofitted by deadlines during the period 1988 to 1990. Systems applied to date primarily use selective catalytic reduction (SCR) technology, which employs ammonia reagent to chemically convert NO_x to normal atmospheric nitrogen. A number of adaptations of typical SCR technology previously utilized in Japan for base-loaded coal-fired boilers are being applied and evaluated in West Germany for use in peaking-boiler service. Such new process designs,

some of which offer potential for significantly reducing the cost of retrofit SCR technology, may prove to be of significant value for possible application in low or high-sulfur de-NO_x service in the U.S.A.

West German influence and its projected capital expenditures for stationary source SO_2 and NO_x control aggregating well in excess of 40 billion West German marks by the early 1990s is bringing about a new and extraordinary, continent-wide effort to accomplish substantial abatement of acid precipitation effects through major and widespread reductions in SO_2 and NO_x emission inventories.

SECTION 1

STATUS OF SO_2 AND NO_x EMISSION REGULATIONS

1.1 WEST GERMAN SO_2 REGULATIONS

Recent acceleration of European activities for reduction of sulfur oxide (SO_2) and nitrogen oxide (NO_x) emissions is centered in the Federal Republic of Germany, (West Germany). Great emphasis has been placed on extensive forest damage, considered to be tied to air pollution, which has occurred in some regions of the country. Effects on trees have been particularly severe in the area of North Rhine-Westphalia in the central portion of the country, as well as Baden Wuerttemberg in the southwest. At the same time the West German coal industry (1) feels that the causes for forest decline in that country have not yet been found.

1.1.1 Key Provisions of Landmark 1983 Legislation

In 1983 West Germany enacted a major national acid rain control directive (GFAVO) (2), (see Table 1-1), that has led to a major program of flue gas desulfurization (FGD) installation at both new and existing boilers, primarily on large coal-fired units. Note that boilers larger than 110 MW(e) have been required to add stack gas cleaning by 1988. Reduction of emissions from smaller boilers, 18 to 110 MW(e), is tied to a 1993 deadline. Requirements are the same for existing oil-fired boilers.

TABLE 1-1
FEDERAL SO_2 CONTROL REQUIREMENTS FOR WEST GERMAN COAL-FIRED BOILERS

Size, MW(e)	SO_2 Emission Limit mg/Nm3 (App. Lb/MMBtu)	Removal	Compliance Deadline	Approx. No. Boilers Existing
Over 110	400 (0.3, Avg.)	85	7/1/88	160
35 to 110	2,000 (1.6, Avg.)	60	4/1/93	370
18 to 35	2,000 (1.6, Avg.)	—	4/1/93	300

Note also that in addition to an absolute limit on the rate of SO_2 emission a minimum %-removal is specified for boilers 35 MW(e) and larger, thus preventing the use of fuel switching to achieve control compliance. The provisions of the directive for fluidized bed boilers in the range of 35 to 110 MW(e) requires that SO_2 emission reduction be 75% (rather than 60%). Informed opinion in West Germany believes that the 400 mg SO_2/Nm^3 (144 ppm) requirement for boilers above 110 MW(e) may well be lowered to approximately 200 mg (72 ppm) or less by 1990 or before. Similarly, the 60%-removal requirement level for 35 to 110 MW(e) boilers may be expected to be increased in the next several years.

1.1.2 Other Stipulations of 1983 GFAVO

After declaration of individual boiler owners by July 1, 1984, any existing boiler larger than 110 MW(e), if committed to being decommissioned by April 1, 1993, is permitted to operate for no more than 30,000 additional hours at an SO_2 emission rate not to exceed 2,500 mg/Nm^3, (900 ppm.)

Additionally, the 1983 law requires that flue gases in the stack following desulfurization must typically have a minimum temperature of 72°C (162°F) as they exit the stack.

Surveillance of SO_2 emission by continuous monitoring and recording of stack SO_2 is required for coal- and oil-fired boilers larger than 18 MW(e). Compliance requires that (3) all daily mean values are equal to or smaller than the emission limit value: 97% of half-hour mean values are equal to or smaller than 1.2 times the emission limit value; and all half-hour mean values are equal to or smaller than twice the emission limit value.

Individual local (provincial) governments have the authority to impose more stringent requirements than those specified by the national legislation. For example, (4) in North Rhine-Westphalia, (with nearly 50% of the electric power generation of the entire country, a large portion being fired with lignite), special requirements were placed on approximately 3,000 MW(e) of existing lignite-fired boiler capacity in 1984 calling for an interim SO_2 emission reduction of 110,000 metric tons per year by 1987 (through temporary low-capital-cost dry-alkali injection means.)

1.1.3 1986 Legislation for Industrial Plants

Emission limits for small existing industrial boilers, e.g. 1% sulfur fuel-fired units larger than approximately 6,500 lb/hour steam generation, the equivalent of approximately 0.5 MW(e), are addressed in new national legislation (TA Luft) of February 27, 1986 (5). With many exceptions, it is specified that boilers emitting more than 5 kilogram SO_2 per hour must limit emissions to 500 mg/Nm^3, (180 ppm).

1.2 WEST GERMAN NO_x REGULATIONS

After enactment of the major 1983 SO_2 legislation, which imposed modest NO_x requirements, concern about NO_x as a contributor to forest damage substantially increased. Following from a "technology forcing" provision of the 1983 law tied to state-of-the-art technical developments, a 1984 accord among federal and provincial environmental ministers in effect substantially reduced the 1983 limits for NO_x. At the same time it called for setting of deadlines by the individual provincial jurisdictions.

1.2.1 1983 and Superseding 1984 Legislation

The limit values legislated in 1983 and those later substituted by sanction of national government in 1984 for coal-fired boilers are as in Table 1-2 (6). Note that existing coal-fired boilers (with future operation of unrestricted duration) as well as new boilers must limit NO_x emission to 200 mg per standard cubic meter, a level equivalent to approximately 100 ppm (volume). An approximate equivalence between the four most common emission concentration measures is: 1 mg/Nm^3 = 0.487 ppm = 0.35 g/GJ = 0.000814 lb/MM Btu (7). This stringent requirement is predicated on commercial experience in Japan indicating that selective catalytic reduction (SCR) technology is effective, and the judgement that it is demonstrated to be capable of reducing emissions to this low level. [NO_x limits, 1984 basis, for new oil-fired units are 150 mg/Nm^3 above 110 MW(e) and 300 mg/Nm^3 from 18 to 110 MW(e). For existing units of unspecified future lifetime the limits are 150 mg/Nm^3 above 110 MW(e) and 450 mg/Nm^3 from 18 to 110 MW(e).]

TABLE 1-2
NO_x CONTROL REQUIREMENTS FOR WEST GERMAN COAL-FIRED BOILERS

Category	NO_x Emission-Limit, mg NO_2/Nm^3 (ppm), (6% O_2 Basis, Dry Bottom: 5% O_2 Basis, Wet Bottom)	
Size, MW(e)	18 to 110	Over 110
New Units, Dry Bottom:		
1983	800 (400)	800 (400)
1984	400 (200)	200 (100)
New Units, Wet Bottom (Slag-Tap):		
1983	1,800 (900)	1,800 (900)
1984	400 (200)	200 (100)
Existing Units, Dry Bottom:		
1983	1,300 (650)	1,300 (650)
1984	650 (325)	200 (100)
Existing Units, Wet Bottom (Slag-Tap):		
1983	2,000 (1,000)	2,000 (1,000)
1984	1,300 (650)	200 (100)

Note: 200 mg/Nm_3 equals approximately 0.16 lb/MM Btu.

Note, however, that at the option of boiler owners, as decided and declared by them in 1984, old boilers aggregating approximately 12,000 MW(e) capacity will be phased out, i.e. retired, no later than 1993 after no more than 30,000 additional hours of operation, during which they will be allowed to emit 650 mg NO_2/Nm^3, i.e. approximately 325 ppm, (1,300 mg/Nm^3 for wet bottom), above 18 MW(e), (450 mg/Nm^3 for oil-fired units.)

As in the case of SO_2, surveillance of NO_x emissions by continuous monitoring and recording of stack NO is required for coal- and oil-fired boilers larger than 18 MW(e). Compliance requires that all daily mean values are equal to or smaller than the emission limit value: 97% of half-hour mean values are equal to or smaller than 1.2 times the emission limit values and all half-hour mean values are equal to or smaller than twice the emission limit value.

The state government of Baden-Wuerttemberg, the area of greatest forest-damage severity was the first to impose prompt deadlines for the stringent 1984 NO_x emission limits (8). Dry bottom boilers, both new and existing, must comply by 1988, wet (molten-ash) bottom boilers by 1990. Similar deadlines have also been established by other state jurisdictions including North Rhine-Westphalia. It is expected that the retrofitting of NO_x removal systems on existing West German boilers larger than 110 MW(e) will be completed by 1990 resulting in an average of 70% reduction in NO_x emissions.

1.2.2 Comparison with U.S.A. and Japan

The extremely stringent 200 mg/Nm^3 requirement for both new and existing coal-fired boilers above 110 MW(e) size surpasses NO_x control requirements in all other nations including Japan. See Table 1-3 (9). The West German NO_x stringency for boilers above 110 MW(e) is all the more remarkable, taking into account that most NO_x emissions are from mobile sources. (Note that additional regulations are being considered in West Germany that will require lead-free fuel and catalytic converters for gasoline-fueled automobiles.)

TABLE 1-3
COMPARISON OF NO_x EMISSION STANDARDS FOR COAL-FIRED UTILITY BOILERS

Country	NO_x Emission Standard, mg as NO_2/Nm^3 (6% O_2)
West Germany, New and Existing over 110 MW(e), (1/2 hr. avg.)	200
U.S.A., New Sources	600-750
Japan, after 1987	410

1.2.3 Technological Implications of Stringent Control Requirements

Commercially developed combustion modifications for NO_x control are expected to be routinely applied, primarily on dry-bottom boilers. However, the very substantial reduction that will be required from the uncontrolled NO_x emission levels illustrated by Table 1-4 (6) is resulting in widespread application of SCR to essentially all German boilers larger than 110 MW(e). Moreover, since it is necessary to sustain ample boiler temperatures in wet bottom boilers sufficient to maintain bottom ash in a molten state, only minor reduction in NO_x emission can be achieved by combustion modification; and wet bottom boilers will require SCR removal efficiencies as high as 90%.

TABLE 1-4
TYPICAL PRE-CONTROL BOILER NO_x EMISSIONS

Type Boiler	Actual Emission mg as NO_2/Nm^3 (6% O_2)	
	Range	Mean
Bituminous, Wet Bottom (Slag-Tap)	800-2,800	1,700
Bituminous, Dry Bottom	800-1,500	1,200
Lignite, Tangentially-Fired	400-700	500

1.2.4 Other Legislation in Europe

By influence of West Germany significant NO_x control legislation has also passed or is pending in Austria, Switzerland, The Netherlands, Denmark, Sweden and the European Economic Community. See Table 1-5 (7) displaying the NO_x emission management objectives of governing officials of EEC, (10) revised in 1985 to call for emission rates throughout Europe after 1995 comparable to current requirements in West Germany. New standards in Austria for coal-fired boilers above 110 MW(e) call for 150 mg/Nm^3 for new boilers and 300 mg/Nm^3 for existing boilers (11).

TABLE 1-5
EFFECT OF AMENDED EUROPEAN COMMUNITY DIRECTIVE

	Emission Limits (mg NO_2/Nm^3)		
1983 Proposed Directive	**Coal**	**Oil**	**Gas**
All Plants over 50 MW(t)*			
to 1995	800**	450	350
after 1995	400***	220	180
1985 Amended Directive			
to 1995: over 50 MW(t)		450	350
50-100 MW(t)	800**		
100-300 MW(t)	800		
over 300 MW(t)	650		
after 1995: over 50 MW(t)		150	100
50-100 MW(t)	400***		
over 100 MW(t)	200		

*Note that 100 MW(t) equals approximately 37 MW(e).
**1300 mg/Nm^3 for slag tap furnaces
***800 mg/Nm^3 for slag tap furnaces

1.2.5 1986 Legislation for Industrial Plants

The new federal regulations (TA Luft) issued on February 27, 1986, limit NO_x emissions from industrial plants with an output of more than 5 kilograms as NO_2 per hour, generally to a limit of 500 mg/Nm^3. (As noted earlier, the SO_2 emission limit for industrial plants with an SO_2 output of more than 5 kilograms per hour has been set a a nominal level of 500 mg/Nm^3).

Other new NO_x limits imposed by the February 1986 legislation are as follows:

- o Solids incineration, less than 50 MW(t), i.e. 18 MW(e)
  - Fluidized bed, more than 20 MW(t) — 300 mg/Nm^3
  - Other — 500 mg/Nm^3
- o Oil incineration, less than 50 MW(t) — 250 mg/Nm^3
- o Gas incineration, less than 100 MW(t) — 200 mg/Nm^3
- o Gas Engines
  - Diesel
    - More than 3 MW(t) — 2,000 mg/Nm^3
    - Less than 3 MW(t) — 4,000 mg/Nm^3

- Otto	
Four-stroke	500 mg/Nm^3
Two-stroke	800 mg/Nm^3
o Gas turbines	
- More than 60,000 Nm^3/h exhaust	300 mg/Nm^3
- Less than 60,000 Nm^3/h	350 mg/Nm^3

SECTION 2

STATIONARY SOURCE FLUE GAS DESULFURIZATION DEVELOPMENT AND APPLICATION

2.1 BOILERS AFFECTED BY 1983/1984 WEST GERMAN LEGISLATION AND ACCORDS

2.1.1 Size of FGD Market

Table 2-1 shows the number and size of existing West German boilers, almost all firing low-medium sulfur fuel, generally bituminous coal or lignite, and indicates that more than 150 units are impacted by the 1988-deadlined SO_2-control requirements (12). Also affected are 7,400 MW(e) of new, coal-burning units (13) under construction or expected to start up by approximately 1990.

TABLE 2-1
POPULATION OF EXISTING WEST GERMAN COAL- AND OIL-FIRED BOILERS

Size, MW(e)	Number	Aggregate MW(e)	Average MW(e)
Above 300	41	18,400	450
135-300	91	17,800	195
75-135	95	9,900	104
30-75	378	18,500	49
9-30	548	10,600	19
Above 9 (Total)	1153	75,200	-

2.1.2 Principal Boiler Fuels in Use

Furnaces of size greater than 110 MW(e) size are almost exclusively fired with hard (bituminous) coal or lignite. The sulfur content of the hard coal is about 0.7-1.2% (in future up to 1.5%), with ballast coal containing as high as 2.7% sulfur; of wet raw lignite, 0.3-1.2%.

2.2 OVERVIEW OF PRINCIPAL FGD TECHNOLOGY APPLICATION

2.2.1 Impact of 1983 West German FGD Legislation

In keeping with the 1988 target compliance-date almost all utility units are now being retrofitted with scrubbers except for approximately 12,000 MW(e) of capacity (14) to be retired by 1993 after no more than 30,000 additional hours of operation. More than 100 FGD installations, primarily commercial-gypsum-producing types, comprising more than 35,000 MW(e) are being erected. Approximately 50,000 MW(e) of FGD is expected to be in place by the early 1990s (15).

Comparatively new boilers under 110 MW(e) have been retrofitted with FGD to date since the compliance deadline is 1993. In the absence of a %-removal stipulation in the 1983 law, boilers smaller than 35 MW(e) may be expected to typically rely on fuel modifications/switching as needed to meet the specified 2,000 mg/Nm^3 (720 ppm) SO_2 emission limit.

The many hundreds of West German boilers in the size range, 35 to 110 MW(e), that will require SO_2 removal in the amount of 60% (or possibly substantial greater) by 1993 represent a very large ongoing FGD market rivaling the magnitude of cost of the many large systems now under construction under the 1988 deadline. If reports and indications of an adequate gypsum market are believed and accepted, and particularly if control requirements are modified to call for SO_2 removal efficiency substantial higher than 60%, substantial use of gypsum-producing limestone scrubbing systems would be expected to result. However, if newer wet scrubbing technologies that can competitively generate more valuable and attractive by-products become commercially available, many applications could occur. Proponents of economical dry and semi-dry SO_2 removal processes for use in this market appear to face substantial uncertainties in view of possible major difficulties in solid waste management, and, in some instances, due to characteristically large and undesireable fluctuations in boiler load and fuel characteristics.

Sulfur dioxide emissions in West Germany of 4 million metric tons per year, approximately 80% of which originates from utility and industrial boilers, are expected to be reduced by almost two thirds by 1988. The cost for these FGD installations has been projected to be as much as 15 billion German marks.

A retrofit wet limestone FGD system augmented by post-scrubbing with caustic liquor will go into service at the large North Munich coal-fired power plant in 1989 with a guaranteed SO_2 emission limit of only 25 mg/Nm^3, i.e. 9 ppm, and may, because of technology-forcing provisions of the 1983 GFAVO legislation, become the basis for a new and far more stringent, SO_2 emission standard for large boilers.

Influenced by the new control activity in Germany, approximately 2000 MW(e) of usable-gypsum-producing FGD systems are being installed in The Netherlands, and a major FGD installation program is under way in Austria on utility boilers.

2.2.2 Source of FGD Technology Used

Lime/limestone scrubbing is the principal FGD method being used. Table 2-2 illustrates the manner in which the very large lime/limestone FGD market, (approximately 93% of all capacity sold to date,) has been shared by the six principal system suppliers, with West Germany thereby using a mix of Japanese, U.S. and German design technologies (14).

As in Japan, most of the installations of each principal supplier are designed to employ forced oxidation to yield a commercially usable by-product gypsum and to thus avoid the substantial cost and complexity in Europe of alternative throwaway-waste management.

TABLE 2-2
PRINCIPAL LIME/LIMESTONE SYSTEMS APPLIED

Supplier	Approx. Aggregate MW(e)	Approx. No. of Install.
Deutsche Babcock	9,000	30
Mitsubishi/Thyssen	5,000	15
Chemico-Mitsui/Steinmueller (GEESI)	6,000	15
Research Cottrell Double-Loop	4,000	10
Saarberg-Hoelter-Lurgi Buffered Limestone	6,000	20
Bischoff Single-Loop	4,000	20
Total	34,000	110

2.2.3 Current Generic Design of Lime/Limestone FGD Systems

Much like the common process design practice in U.S. during the 1980s, the most typical FGD system arrangement that has recently been extensively applied in European electric-utility applications (see Figure 2-1) incorporates the following features:

- o Lime or limestone reagent use, with limestone generally preferred
- o Spray tower type absorber design, rubber-lined
- o In-situ forced oxidation facilities installed in the sump of the absorber without use of sulfuric acid reagent for pH depression/adjustment
- o Primary dewatering of gypsum slurry by liquid cyclones, final dewatering by centrifuge or horizontal vacuum filter
- o Production of a throwaway or usable grade of gypsum
- o Single-loop systems that omit low-pH pre-scrubbing used extensively in Japan and in many early German installations for segregated removal of hydrogen chloride and other minor raw-gas components

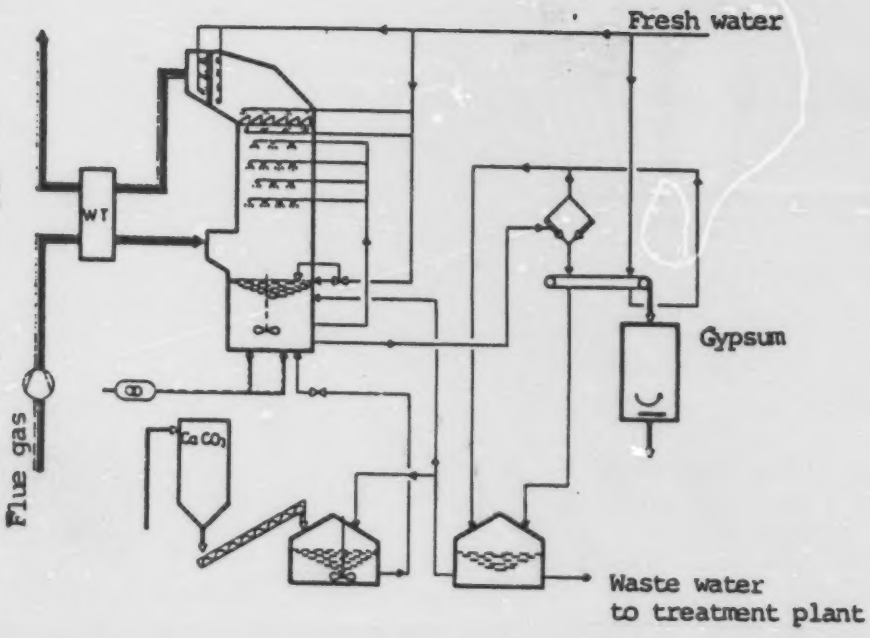


Figure 2-1. Schematic diagram of a limestone FGD plant.

2.2.4 Contrast with U.S. FGD Practice

Application of FGD in West Germany differs significantly from that in U.S.A. in a number of respects:

- o Coal sulfur level is comparatively low in Germany, and as a result it has been possible to establish high (95%) availability system design without use of spare scrubber modules.

- o Due to transportation-economics some early installations in Germany use lime in lieu of limestone for FGD reagent. However, as a universal energy conservation measure, many recent FGD installations under construction have been dedicated to use of limestone reagent, and 80% of installation capacity to date uses limestone (16).

- o Due to comparatively low coal sulfur levels and short shipping distances, limestone reagent supply is generally ground at the mine-source rather than at the boiler site.

- o In mainland Europe the use of throwaway-solid-waste processes, including dry or semi-dry scrubbing methods feasible for low-sulfur fuel applications in Scandinavia and U.S.A., is curtailed in large utility applications by present lack of effective means of utilizing sulfite-containing FGD waste and of adequate landfill disposal space. (Nonetheless, a total of 30 wet throwaway waste systems comprising 9000 MW(e) are being installed in West Germany, all at minemouth lignite-fired plants where disposal of solid waste in the mine is anticipated.)

- o Due to comparatively high energy cost in Europe, flue gas reheat is generally achieved by recovery of heat from the FGD inlet gas. Rotary and tubular regenerative heat exchanger systems are being commonly used in West Germany for the purpose of meeting the mandatory 72°C (162°F) minimum stack outlet temperature requirement without use of augmental energy supply for gas reheat.

- o Due to conservative FGD-buyer policy and the unusual stringency of stack emission monitoring required to be tied to half-hour mean values of emission rate, systems are frequently specified for a substantially lower stack emission rate than the GFAVO emission limit value.

2.3 DETAILS OF FGD TECHNOLOGY USED

2.3.1 System Characteristics of Lime/Limestone FGD Suppliers

A brief process description of the most common FGD installations of the principal firms is as follows:

Deutsche Babcock: This most frequently applied FGD process uses a single or two-stage limestone spray-tower absorber followed by post-reaction with forced oxidation in the sump (16). In an initial installation, magnesia additive enhances SO_2 absorption and internal scale control, and pH control in the forced oxidation step is achieved with sulfuric acid reagent feed. Many subsequent installations instead achieve forced oxidation at the normal low pH in the scrubbing-slurry post-precipitation section at the bottom of the absorber (in-situ).

Mitsubishi/Thyssen: In the conservative design of Mitsubishi, which is the largest FGD system supplier in Japan, individual wet process loops are used for gas quenching (chloride removal) and for grid-packed-tower SO_2 absorption. Earliest German installations are ex-situ forced oxidation with pH adjustment by sulfuric acid. All recent German systems being supplied use in-situ forced oxidation in the SO_2 absorber sump without use of sulfuric acid reagent feed (17).

Chemico-Mitsui/Steinmueller (GEESI): Initial installations have included Chemico (GEESI) spray-tower absorbers and use of the Mitsui ex-situ forced-oxidation system from Japan employing oxidation catalyst and sulfuric acid. Subsequent installations in Germany have incorporated the oxidation step in the bottom of the absorber tower (as in the case of applications of the process in U.S.A.), and this in-situ design eliminates the use of catalyst and sulfuric acid (18).

Research Cottrell Double-Loop: Research Cottrell's familiar double-loop in-situ limestone scrubbing process now extensively used in Germany has been the most common forced-oxidation FGD process applied in the U.S., (and accounts for most usable-gypsum producing FGD installations in operation or under construction here.) With large scale use of by-product gypsum in Germany for plaster/mortar products that tolerate elevated chloride levels, some Research Cottrell installations include provision for advantageous drying of the cake product through waste heat recovery by direct contact with a portion of the scrubber inlet-gas stream (19).

Saarberg-Hoelter-Lurgi (SHL) Buffered Limestone: In a unique limestone slurry scrubbing process that uses a combined co-current/counter-current absorber design, SHL utilizes organic (formic) acid buffering in conjunction with in-situ forced oxidation (20). Saarberg-Hoelter no longer markets its earlier process design, which used lime reagent and recirculated a high-chloride-level clear liquor supplied by thickener overflow. In at least one installation this supplier is using the plant cooling tower casing in lieu of a conventional flue-gas stack to discharge the FGD outlet gas, an exhaust arrangement that the West German acid rain legislation (GFAVO) exempts from the 72°C (162°F) minimum stack-exit-temperature requirement. See Figure 2-2.

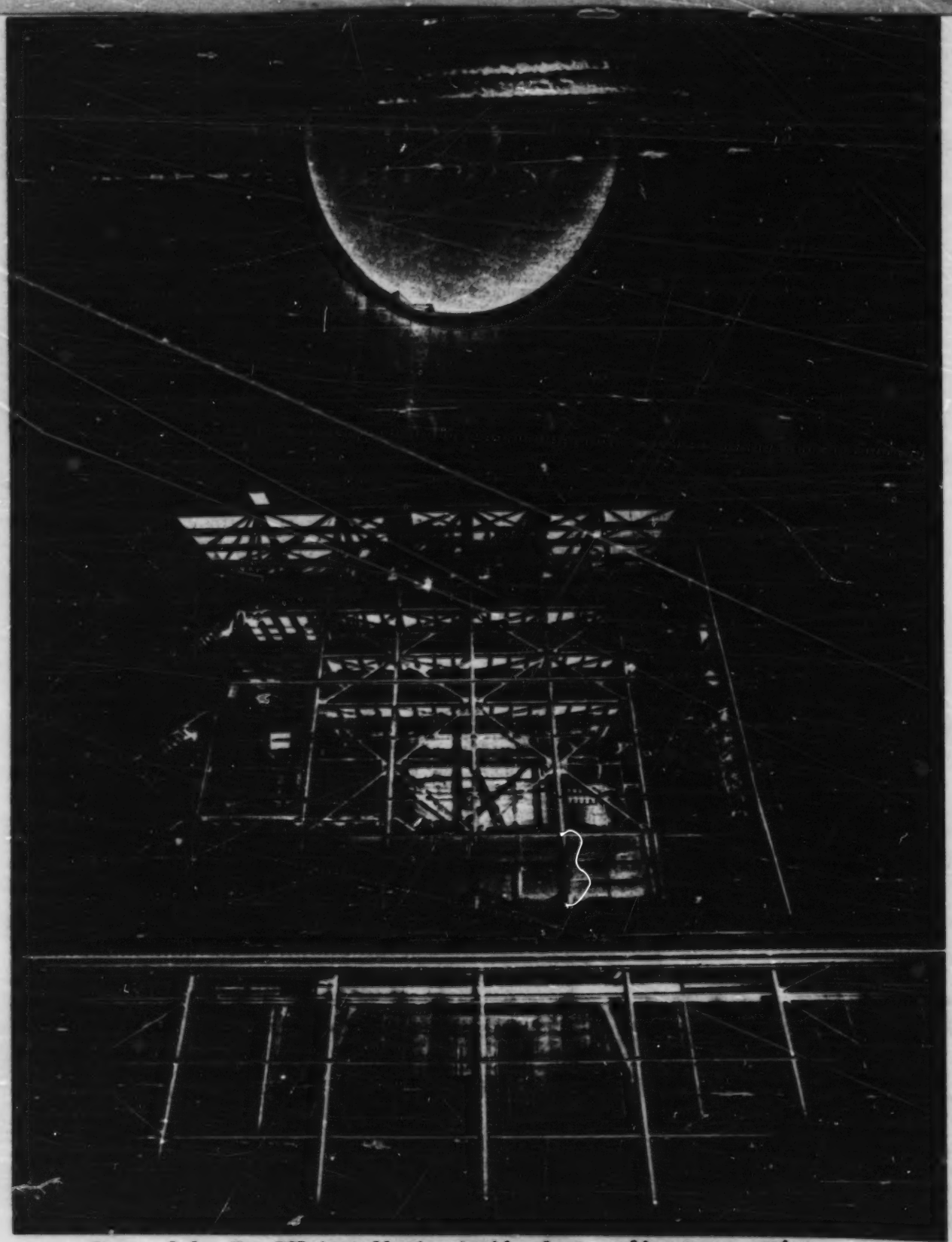


Figure 2-2. Wet FGD installation inside plant cooling-tower casing.

Bischoff Single-Loop: German supplier, Gottfried Bischoff, with a substantial commercial background in supply of large-capacity wet-scrubbers for the iron and steel industry in the 1960s, has at the outset of its FGD system supply activity installed a number of comparatively simple, single-module, approximately 200 ft. high by 40 ft. diameter, lime/limestone FGD spray towers of over 400 MW(e) capacity designed with in-situ forced oxidation in the sump. An early installation on the North Sea uses seawater for FGD makeup water yet, by adequate by-product classification and fresh-water washing, achieves a gypsum yield used for commercial-scale wallboard manufacture (21). See Figure 2-3.

2.3.2 Operating Experience

Many FGD facilities already in service in West Germany are the result of a comparatively modest control program that began prior to 1983 under the jurisdiction of individual provincial governments, which led to twenty FGD applications. Thus, although widespread application of FGD in the Federal Republic of Germany (West Germany) is comparatively recent, as of the end of 1984 almost 3000 MW(e) of lime/limestone scrubbing systems were in operation, all of single-module slip-stream design to meet requirements of pre-1983 legislation. These FGD system installations are reported to have provided acceptable reliability and performance. However, German electric utility specialists note that with only partial scrubbing of plant flue gas output these earliest installations have not been subjected to typical full-scale electric-utility-industry operating conditions requiring high availability at sustained high/variable load.

Additional FGD capacity of more than 5000 MW(e) originating from the 1983 legislation has now come on line, but is in an early stage of sustained operation without a lengthy period of experience. However, based on a recent overview (22), system availability of 90 to 95% is being achieved after twelve months of initial operation. Substantial debugging problems/efforts have typically been encountered during the initial operations, and primarily with the gypsum solids processing equipment, i.e. centrifuges, thickeners, filters, dryers and storage facilities, and solids loading and unloading. Thus, Germany's massive FGD program is seen to be at too early a stage of implementation to be able to show broadly demonstrated success or to thoroughly characterize performance and reliability of system designs that are being applied.

Operating with characteristically low or moderate coal sulfur level, and applying commercially demonstrated and conservatively designed forced-oxidation systems, no critical technical problems have been experienced or forecast at the present time. Moreover, because of the comparatively low coal sulfur level, availability concerns have not required the use of spare scrubbing modules. Feasibility of regenerative flue-gas reheat using rotary regenerative heat exchangers has been effectively demonstrated. FGD retrofitting has not presented insurmountable problems.

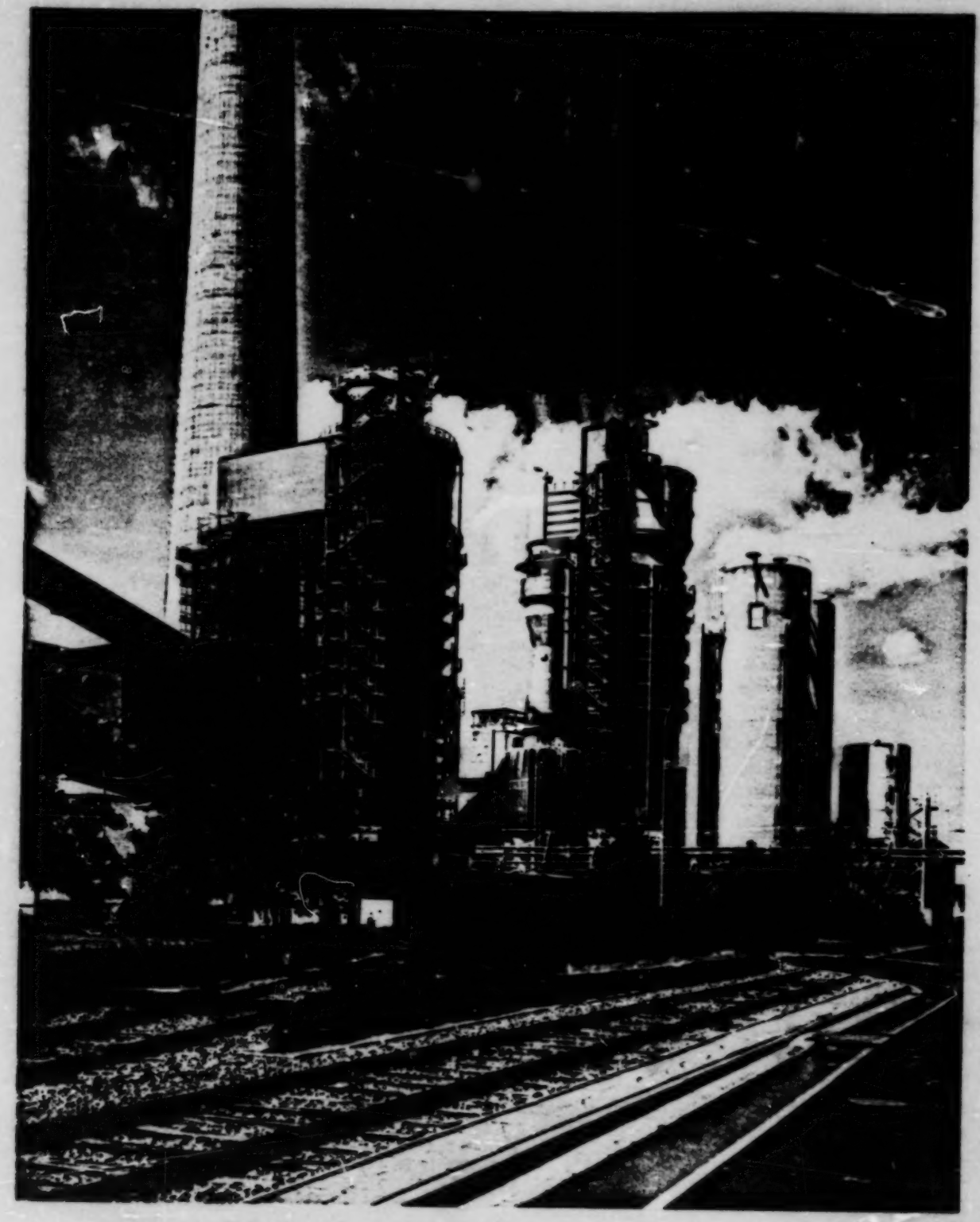


Figure 2-3. Two 400 MW(e) wet FGD modules.

However, there is concern about, and great attention is being given to means of ensuring commercial utilization of as much as 5 million annual metric tons of anticipated ultimate FGD gypsum production. New technologies are developed and are being promoted for reprocessing some of the by-product to anhydrite and alpha hemihydrate forms so as to supply available markets beyond those anticipated for normal gypsum alone (23).

Through wastewater purge treatment carried out in the presence of gypsum precipitation from $CaSO_4$-supersaturated liquid, very low trace metal concentrations are achieved prior to outfall discharge (24). Unlike Japan, where common production of usable FGD gypsum in lieu of throwaway solid waste also requires a purge of FGD process liquor, German boilers are typically inland on fresh water streams and do not have seawater receiving-bodies to which to discharge FGD chloride-liquor blowdown from usable-gypsum-producing FGD operation. Due to the significant potential impact of the chloride blowdown on some German rivers a major policy decision by the national government is understood to be pending on acceptable long-term means of FGD-chloride-waste management.

2.3.3 Minor Processes

A number of alternative regenerative and throwaway-waste SO_2 removal processes are being applied or developed in Europe.

Wellman Lord: The familiar Wellman Lord Process using clear sodium sulfite liquor scrubbing has been applied in approximately six plants in Europe equivalent to approximately 2000 MW(e) aggregate capacity, with either liquid SO_2 or elemental sulfur by-product yield (25).

Walther Ammonia: In four installations aggregating 750 MW(e) orders have been placed for the Walther Process which uses ammonia scrubbing to produce ammonium sulfate by-product liquor that is converted to a dry fertilizer product in a small auxiliary spray-dryer system. One of the installations of 70 MW(e) capacity is designed for removal of NO_x in a second ammonia scrubbing stage, operating in an absorption-oxidation mode utilizing ozone oxidant, but it is understood that this wet NO_x removal technique may be abandoned (5). Although highly publicized problems with a visible ammonia stack plume at a 240 MW(e) operation that started up in 1983 have blocked the other installations, an engineering solution (26) has been achieved through use of high-gas-pressure-drop mist eliminator equipment. One or more new installations are understood to be now underway.

Sodium Adipate Process (27): This regenerative process that yields concentrated SO_2 has evolved from citrate FGD process technology and is being offered commercially in West Germany for low-sulfur coal-fired boiler service for which the citrate process is not applicable. The operating costs for controlling strong industrial SO_2 emissions are said to be attractive compared to Wellman Lord.

Ispra Mark 13 A Process (28): This regenerative process under development by the Commission of the European Communities Joint Research Centre converts flue gas SO_2 into sulfuric acid by reaction with a dilute solution of bromine, which is regenerated by electrolysis. Bench-scale operation has been successfully completed and an approximately 32,000 m^3/hour field pilot plant operation in Sardinia, Italy, is scheduled for 1988/9.

Flakt-Hydro Process (29): This low-capital-cost wet FGD process utilizing once-through seawater for SO_2 removal is applicable to boilers firing oil or coal with up to approximately 2% sulfur and has been applied for stack gas cleaning equivalent to 1430 MW(e), almost entirely in Norway.

Dry Scrubbing: A number of small and large boilers aggregating over 4,000 MW(e) (a substantial number in West Germany) are being equipped with conventional throwaway-waste dry scrubbing system using spray dryers (30). In instances where suitable solid waste management schemes are made available, this technique may be expected to be applied to additional existing West German boilers of size 110 MW(e) and less by a 1993 startup deadline. In FGD-using European countries other than West Germany, including Denmark, Austria, and Italy, conventional dry scrubbers are recently being applied at substantially higher inlet flue-gas SO_2 concentrations (as high as 7000 mg SO_2/Nm^3) than earlier applications worldwide. In some countries, particularly Sweden, conventional dry scrubbers are being installed downstream of high-efficiency fly ash collection equipment to more readily permit the FGD solid waste to be converted to a generally usable by-product.

Circulating-Fluid-Bed-Scrubber: This hydrated-lime-using dry-scrubbing type system of Lurgi Corporation, designed to operate upstream of the electrostatic precipitator, is unique because of the unusually high coal sulfur levels at which it is being applied (31). A 50 MW(e) unit, (see Fig. 2-4) that began operation in 1984 removes 95% SO_2 from a flue gas from lignite firing containing 4,250 mg SO_2/Nm^3 (1500 ppm), and a 125 MW(e) installation under construction is designed for 97% SO_2 removal in a low-grade lignite service with inlet flue gas containing 13,000 mg SO_2/Nm^3 (4700 ppm.) The operating system achieves 95% availability and lime/sulfur stoichiometric ratio of 1.7 with the outlet gas temperature at a 27°F approach to the wet bulb temperature. In an upward-flow dry/semi-dry reactor, inlet flue gas fed via an extended venturi nozzle is mixed with a finely pulverized hydrated lime and injected water. A relatively high flue-gas velocity of between 6.5 and 26 ft/sec carries unreacted lime and reaction products out of the top of the reactor. Later, solids are separated from the flue gas in the downstream particulate collector, typically a combination mechanical collector and electrostatic precipitator, and a portion of it is recirculated to the reactor to significantly increase solids residence time and utilization.

Lime/Limestone Injection into a Multistage Burner (LIMB): Principal worldwide application of LIMB to date is in lignite-fired boilers in West Germany, where approximately 3000 MW(e) of existing lignite-fired capacity will be retrofitted for temporary SO_2-emission-reduction duty in North Rhine-Westphalia by 1987 (4).

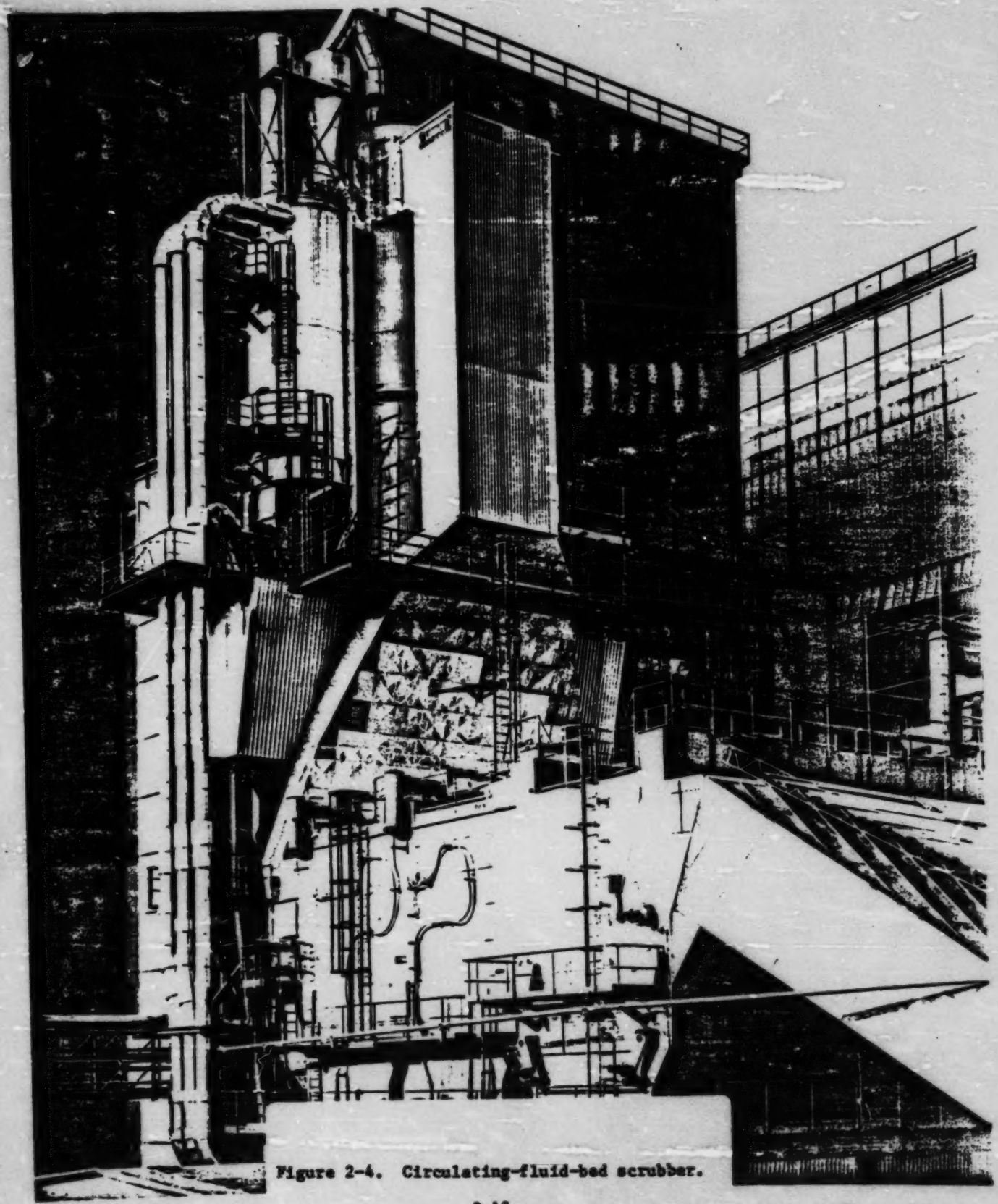


Figure 2-4. Circulating-fluid-bed scrubber.

Significant precipitator fouling problems and poor SO_2 removal efficiency are reported for a full-scale 700 MW(e) test in Germany in bituminous coal-fired service using limestone fed near the burners (32). In full scale tests at 125 MW(e) at another bituminous coal boiler in Germany limestone and hydrated lime reagent were fed alternately near the boiler-furnace outlet. With 2 moles of sorbent feed per mole of inlet SO_2, removal efficiency was 32% with limestone and 44% with hydrated lime. Somewhat poorer results were achieved in limestone injection tests in a pulverized bituminous coal-fired boiler in Malmo, Sweden. In short-term furnace injection tests in a small bituminous coal-fired unit in Germany similar low removal efficiencies were measured (33).

In Finland a new 250 MW limestone injection system, May 1986 startup (34), gains only 30% removal in the furnace but incorporates a tail end activation reactor (simplified spray-dryer type contactor) to humidify the flue gas upstream of the electrostatic precipitator to gain an overall SO_2 efficiency ranging from approximately 60% to over 80% with flue-gas-temperature approach to the wet bulb temperature ranging from 36°F to 9°F, respectively. The unit is in peaking service firing low sulfur bituminous coal.

2.4 TYPICAL DESIGN PRACTICES

2.4.1 Materials of Construction

Except for Research Cottrell installations, which, as in the U.S.A., emphasize use of stainless steel construction, materials of construction in German lime/limestone FGD installations are typically as follows (35):

Scrubbers:	
- Casing	Mild steel, soft rubber lined
- Flue gas inlet	Refractory lined
- Spray nozzles	Stainless steel, ceramic, and silicon carbide
- Oxid. air distribution	Stainless steel and plastic
- Mist separator profiles	Polypropylene
Casing	Mild steel, rubber lined
Washing nozzles	Polypropylene
Tanks, vessels:	
- Large	Mild steel, rubber lined
- Small	Plastic

Regenerative Flue Gas Reheat:	
- Rotary Heat Exchanger	
Raw gas connections	
hot	Mild steel, flake glass lined
cold	Mild steel, rubber lined
Clean gas connections	Mild steel, rubber lined
Casing	Corten steel
Rotor structure	Corten steel
Heat storage, cold side	Plastic
Heat storage, hot side	Enameled steel
- Tubular type	
Casing	Mild steel, flake glass lined
Tubes, hot side	Mild steel
Tubes, cold side	PTFE or PVDF
Flue Gas Ducts:	
- Ducts	
dry and hot	Mild steel
wet	Mild steel, rubber lined and flake glass lined
- Dampers, Casing	
dry	Mild steel
wet	Mild steel, rubber lined
- Disks	Mild steel; mild steel, rubber lined; and stainless steel
- Expansion Joints	Fabric with PTFE foil, and Viton
Mechanical Equipment:	
- Flue gas fan, dry	Mild steel
- Flue gas fan, wet	
Impeller	Stainless steel
Other parts	Mild steel, rubber lined
- Pumps	Stainless steel
- Agitators	Mild steel, hard rubber covered
- Hydrocyclones	
Feeding system	Mild steel, rubber lined
Cyclone	Porcelain and polyurethane
- Vacuum belt filter	
Frame	Mild steel
Drum, etc.	Mild steel, rubber lined
Filter cloth	Fabric with natural rubber
Vessels	Mild steel, rubber lined; GRP; and polypropylene

Piping and Accessories:	
- Pipes and valves	Mild steel, rubber lined; GRP; and polypropylene
- Butterfly valves	
Casing	Mild steel, rubber lined
Disks	Stainless steel, Hastelloy, and mild steel, rubber lined

2.4.2 Flue Gas Reheat

Inline non-regenerative reheating of water-saturated flue gas in the amount of 50°F, the approximate minimum increment needed to meet the 162°F minimum stack exit temperature requirement in Germany, represents 1.6% of boiler heat input for a large power plant unit. Thus, energy economics for high capacity-factor operation in that country has provided strong motivation for commercial application of regenerative reheat means. Rotary air heaters, similar to those commonly used for regenerative combustion-air preheating in large boilers, have been extensively used for this purpose with more than forty purchased and more than fourteen already in operation (36). (See Fig. 2-5.) Reliable operation of these heat exchangers has been tied to application of suitable materials of construction, favorable continuous performance of electrostatic precipitators dedusting the hot inlet gas, and use of high-efficiency horizontal-gas-flow type mist eliminators limiting carryover of FGD scrubbing slurry. On-line, intermittent, high-pressure water washing means have effectively prevented exchanger gas pressure drop (the sum of pressure drop across both sides) from exceeding a nominal 125% of the design value for clean conditions. Due to the inherent design of the rotary exchanger, 3-5% of design gas flow leaks from the high pressure side to the low pressure side. When, typically, the FGD booster fan is positioned on the hot dirty gas side a substantial decrease in SO_2 removal occurs. However, a low-leakage design has been developed for this system arrangement that has commercially demonstrated a leakage rate of no more than 0.5% (37).

A comparatively simple, tubular-heat-exchanger type, regenerative reheat system requiring no added flue gas ductwork is also gaining commercial use in Germany after long-term field testing in a lignite FGD installation. Tubes exposed to scrubbed gas are supplied in non-metallic construction and circulating water is the heat transfer medium. Four such systems of an aggregate FGD capacity of 1,200 MW(e) are currently being installed (21).

In one case in Germany the wet FGD system is sited inside a hyperbolic cooling tower serving the power plant, the FGD outlet gas intermixing with a stream of air flow approximately twenty-five times greater. Because of good atmospheric dispersion assured through discharge of the FGD exhaust combined with this substantial air flow the FGD system is exempted from normal FGD stack exit temperature regulations. For corrosion control a double coating of epoxy is applied to the internal surface of the concrete casing of the cooling tower. The capital cost is reported

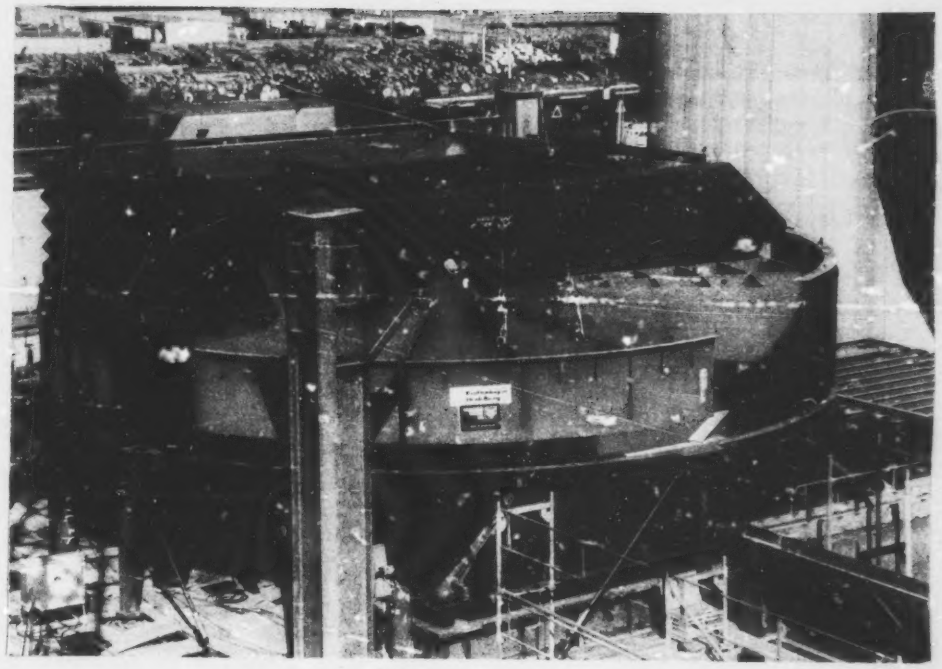


Figure 2-5. Rotary regenerative flue-gas reheater under construction.

to be only 20% of that which would otherwise be required for a conventional flue-gas stack, and only 10% of that which would otherwise be also required for a rotary heat exchanger system for regenerative reheat.

2.4.3 FGD Wastewater Management

The application of usable-byproduct-forming, wet FGD systems, common in Germany, results in a significant discharge of brackish/saline wastewater. With typically high chloride levels (0.1 to 0.2%) in German bituminous coal, FGD wastewater management is a substantial problem. When discharge to receiving streams is not completely prohibited, the rate (38) of FGD liquor outfall is usually limited to the equivalent of 25 U.S. gpm per 100 MW(e). When such saline liquor discharge is allowed, trace metal concentrations, dissolved sulfate, and suspended solids must be reduced to specified levels. A typical wastewater treatment system to accomplish this employing hydroxide precipitation may include two stages of neutralization, flocculation and sedimentation, the first stage operating at pH 9-10 to remove components such as cadmium and manganese, the second stage operating at a pH of 8.5 to remove other components such as zinc and aluminum. An additive in the form of an organic sulfur compound serves as a special precipitation agent to remove mercury. A sludge dewatering facility is also needed.

2.4.4 FGD By-Product Gypsum Management

Commercially usable FGD gypsum production is expected to reach 2.5 million annual metric tons by 1988 and a substantially higher level by 1993. New process developments to convert significant amounts of FGD solids by-product to anhydrite (anhydrous) and unique alpha hemihydrate forms is expected to help ensure fullest utilization of FGD by-product (23). Commercial technology is now available to build plants to process 100,000 metric tons per year of FGD gypsum yielding alpha hemihydrate at a cost of only 50 DM per metric ton (39). As per Table 2-3 commercial use of over five million annual metric tons is ultimately foreseen in West Germany.

Extensive testing by the government of The Netherlands of existing commercial sources of FGD gypsum in Germany has indicated that, while the by-product differs in quality from one power plant location to another, broad commercial use of diverse European FGD gypsum sources may be foreseen (40).

TABLE 2-3
FORECAST OF WEST GERMAN FGD GYPSUM USE

Market	% Replacement of Natural Materials	Consumption, MM Metric Ton/Yr
Plaster, wallboard	Close to 100	2.5 to 3
Floor underlayment	50	0.6 to 1
Portland cement	100	0.5 to 0.6
Mining mortar	50	0.6 to 0.7
Gypsum/wood chipboard	15	0.5 to 0.6
Total	-	5.3 (Avg.)

SECTION 3

STATIONARY SOURCE DE-NO_x DEVELOPMENT AND APPLICATION

3.1 BOILERS AFFECTED BY 1984 LEGISLATION/ACCORDS

Referring to the earlier Table 2-1, it can be seen that more than 150 West German boilers are impacted by the 1984 federal/provincial NO_x control accords requiring reduction of NO_x emissions from units larger than 110 MW(e) to the level of 200 mg NO_2/Nm^3, equivalent to 100 ppm (vol.) and to 0.16 lb/MM Btu heat input. Also affected are 7,400 MW(e) of new, coal-burning units under construction or expected to start up by approximately 1990.

3.2 OVERVIEW OF PRINCIPAL DE-NO_x TECHNOLOGY APPLICATION

The emission limit, (200 mg/Nm^3), set in 1984 for boilers above 110 MW(e) is well beyond the capabilities of combustion modification techniques and requires the use of flue gas cleaning processes for NO_x removal such as SCR and wet or dry sorption. With the resulting requirement for reductions in existing NO_x emissions in the amount of 50-70% or more, post combustion flue gas treatment techniques can be expected to be broadly applied in Europe, especially processes that are capable of removing both SO_2 and NO_x, (and possibly particulates), and that can function adequately in such power plant service. However, because of the early (late-1980s) deadlines for compliance by large boilers in West Germany, and despite the fact that it serves only to remove NO_x, the high developed SCR process is being most broadly assessed, adapted and applied.

3.3 APPLICABILITY OF SCR TECHNOLOGY

Due to concerns about applicability at existing electric utility plants in West Germany of extensive commercial SCR experience in comparatively new, base-loaded boilers in Japan, approximately 50 SCR pilot plant trains have been installed and tested (22) to assess catalyst performance and characteristics. The installations include 24 systems based on conventional SCR application upstream of the air preheater (high-dust), and 19 systems based on use of SCR downstream of FGD (cold-side), including 11 with activated carbon. Extensive high-dust SCR field pilot-scale investigation is taking place because German boilers to be retrofitted with SCR are considered to have a more variable load pattern (more frequent load swings) than those in Japan that have been equipped and operated with SCR, and could cause thermal shock of the catalyst structure. In addition, possible unique effects of fly ash from German coal is of concern. Also, although avoided in Japanese practice and of concern because of ammonia-slippage problems, design NO_x removal efficiency substantially above 80% is specified for a number of the German retrofit SCR applications.

Nonetheless, in the face of all these SCR uncertainties, catalyst-life guarantees have since 1984, increased from 1 year to two years or more (24). Of 10 competing SCR system suppliers in Germany, 6 are licensees of Japanese process licensors while 3 offer German developments including use of activated carbon, ceramic molecular sieve, and iron oxide. For cold-side SCR service (downstream of FGD) activated carbon (coke) is of considerable interest since its catalysis is effective at a comparatively low temperature, i.e. as low as 90°C, (194°F) and requires less reheating of the water-saturated gas prior to the SCR step. An American licensor, Norton, uses a zeolite type catalyst.

As early as 1984 26 specific initial commercial installations were anticipated, several to be applied downstream of FGD because of inadequate plot space to permit normal tie in of the SCR reactor upstream of the air preheater. (See Fig. 3-1) (16). As noted earlier, in some provinces such as Baden-Wuerttemberg, the most heavily forest-damaged area, and North Rhine-Westphalia, the greatest emitting area, the state-administered NO_x control planning is more advanced than in others, and accounts for most NO_x control installations under way to date. The first major SCR facility has been installed on a 460 MW(e) bituminous-coal-fired, dry bottom boiler and commenced operation in early 1986. Another early installation of 160 MW(e) capacity on a bituminous-coal-fired, wet bottom boiler will achieve close to 90% NO_x removal.

3.4 OTHER POST-COMBUSTION CONTROL TECHNIQUES

Other potentially important developments for NO_x removal include sustained pilot and field test programs seeking to adapt existing rotary regenerative air preheaters to incorporate catalyst-coated plates, permitting these facilities to also serve as SCR reactors. Catalyst temperature in this integrated arrangement for high-dust service ranges within the heat exchanger from 150°C to less than 350°C (302°F to less than 662°F), whereas an SCR reactor typically positioned upstream of the air preheater operates at approximately 350°C (662°F).

Full-scale power plant testing (41) indicates feasibility of selective non-catalytic reduction (SNCR) at 1000°C (1832°F) with approximately 50% NO_x removal (without undesirable, partial conversion of SO_2 to SO_3 that accompanies SCR operation). As per Table 4-1, 940 MW(e) of SNCR capability is being installed in West Germany.

A number of pilot plants have been installed in West Germany to investigate use of wet simultaneous SO_2/NO_x removal systems, both of the absorption-reduction and oxidation/absorption types. Wet NO_x removal techniques include a usable-gypsum producing process that is reported to use a ferrous complex ion (FeEDTA) in conjunction with sulfite (and thiosulfite) ions to fix and chemically reduce flue gas NO. This process, now being installed on a full-scale basis, appears to be very similar to the Japanese-proposed technology of the 1970s (42). Although the wet simultaneous SO_2/NO_x processes are seen to have possible economic advantages the tight deadlines (compliance as early as 1988 in many instances) are leading to a preferred use of the more commercially established technology based on SCR.

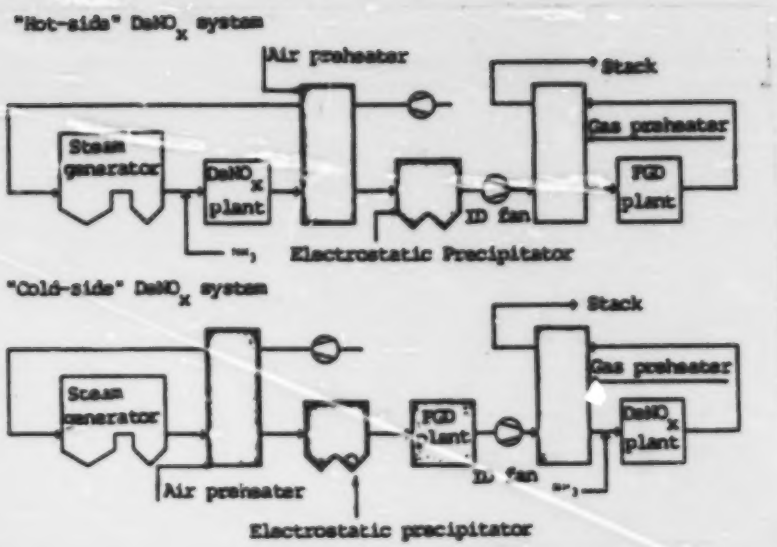


Figure 3-1. Configuration of alternative SCR De-NO_x plants in combination with FGD.

3.5 COMBUSTION MODIFICATIONS

Combustion modifications have been the most common, commercially available means of controlling NO_x emissions at coal-fired utility boilers. For reasons of cost-effectiveness and reliability, combustion controls offering significant NO_x reductions are likely to continue to be the preferred NO_x control approach for both new and retrofit applications in smaller boilers. In general, the most practical and cost-effective retrofit combustion control options are low excess air firing, overfire air, and low-NO_x burners. Note, however, that wet bottom, i.e. slag-tap, type boilers are limited in their ability to apply combustion modifications for NO_x control since generally lower gas temperatures brought about in at least a portion of the furnace would be expected to alter the wet slag properties and possibly hinder its drainage from the bottom of the boiler. Brown coal (lignite) fired power plants (9), constituting another substantial portion of electric power production in West Germany, also present unique problems for NO_x emission control because of special firing arrangements required and because of high water vapor content of flue gas.

Among available options, low-NO_x burners promise the greatest potential for significant (50 to 60%) NO_x reductions and are thus receiving substantial attention in field development activities. Specifically, these burners are designed to control the mixing and stoichiometry of fuel and air in the near-burner region of the furnace to retard conversion of fuel-bound nitrogen to NO_x while still maintaining high combustion efficiency. This is accomplished by controlling the momentum, direction, and quantity of fuel and air streams at the burner throat as they are injected into the furnace chamber.

Few existing coal-fired utility boilers have yet been retrofitted with low-NO_x combustion systems. Retrofitting combustion controls to existing units appears to be technically feasible however, provided sufficient attention is given to site-specific design and engineering. These advanced systems pose new combustion conditions, furnace flow and mixing requirements, and boiler control issues significantly different from conventional burners. Their ultimate success hinges on the ability to integrate these processes with the fixed physical and thermodynamic constraints of the existing boiler. In order to expand the retrofit applicability of these low-NO_x systems, several demonstrations on a variety of boilers are being carried out.

Independently, advanced NO_x combustion control concepts are being developed to more closely control the fuel-air mixing, temperature, and combustion chemistry in the furnace. Reburning technology originated in Japan is under development to destroy NO_x already formed in the initial combustion step. It has been reported to produce a 50% further reduction beyond that of low-NO_x burners.

New boilers in West Germany equipped with recently-developed low-NO_x burners emit 800 mg NO_2/m^3 in the case of dry bottom design and 1,300 mg NO_2/m^3 in the case of wet bottom design (6). In one of the most recent

applications in dry-bottom service low-NO_x burners are being used in conjunction with application of over-fire air to try to achieve an emission rate of 650 mg NO_2/m^3. For new (but not existing) boilers in bituminous dry-bottom service, the Japanesedevised, advanced low-NO_x techique, called "In Furnace NO_x Reduction" (IFNR) or "Fuel Staging" or also "Reburning Technology" holds great long-term promise. It is believed to have the potential to decrease the NO_x level below that achieved with other burner technologies by 30 to 50%. A secondary fuel is injected into the furnace above the main burners and the remaining air for burnout is supplied through ports located above the secondary fuel injection. The secondary fuel will considerably reduce the NO produced in the main combustion zone to yield N2. The fuel staging technique is not commercially demonstrated in coal service and faced with a number of problems connected with burn-out, corrosion and slagging (43). The injection of secondary fuel leads to a high concentration of hydrocarbon radicals in a zone of high temperature and air deficiency. To a great extent these radicals reduce the NO molecules produced in the main combustion zone to N2 (direct NO reduction) or nitrogen compounds, such as HCN and NH_i. This complex process includes both gaseous phase reactions and heterogeneous gas/solid reactions. Combustion in the furnace is completed in the final burnout zone using the balance of combustion-air supply. In this zone the nitrogen compounds formed as intermediate products in the reduction zone are further converted, partly to N2 (indirect NO reduction) and also back to NO. Tests have shown that by this overall process a net reduction of nitrogen oxides by about 50% can be achieved. The development of firing systems using the IFNR principle by staging the fuel supply in the furnace chamber is actively pursued by a number of companies and institutions in Japan, Germany, and U.S.A. Full-scale experience has been gained with oil-firing systems. As to its application to coal firing systems, first test results have up to now only been obtained in pilot-scale plants. Development has been started on injecting the secondary fuel into a burner-related arrangement, i.e. achievement of staged fuel supply to the individual coal flame. It is expected that in-furnace NO_x reduction (reburning) will soon be applied to some pulverized coal-fired boilers after further current operation of this furnace-staging method on a 40 MW(e) gas-fired boiler. In conjunction with flue gas recirculation NO_x emission rates comparable to these from gas firing can be ultimately foreseen through this combustion-modification method for coal and heavy oil fuels.

There are some fluid bed boilers under construction but the experience with existing ones has not been free from problems, particularly in the case of circulating-bed types (22).

SECTION 4

SELECTIVE CATALYTIC REDUCTION (SCR)

4.1 OVERVIEW

4.1.1 Process Description

The SCR process is based upon treating the flue gas with ammonia (NH_3) to chemically reduce NO_x in accordance with the following chemical reactions:

$$4NO + 4NH_3 + O2 \text{ ---------- } 4N2 + 6H_2O$$

$$2NO_2 + 4NH_3 + O2 \text{ ---------- } 3N2 + 6H_2O$$

The reactions proceed when the gas temperature is from 800°C to 1000°C (1470°F to 1830°F), which is the basis for the selective noncatalytic reduction method. However, in the presence of a suitable catalyst, the reaction proceeds with a gas temperature of 300°C to 400°C (570°F to 750°F), which is close to the temperature of the flue gas as it exits the boiler economizer section upstream of the air preheater. This is the basis for the utility SCR process, which is theoretically capable of achieving 85 to 95% NO_x removal for ammonia injections of .85 to 1 mole NH_3 per mole of NO present. Note also that when the SCR operation is carried out downstream of FGD (cold-end) the limited presence of SO_2 and SO_3 in the flue gas makes it possible to utilize catalyst with higher NO_x activity permitting efficient SCR operation at as low as 200°C (392°F).

Typical catalysts (44) are of honeycomb design. Flue gas still containing the fly ash enters square channels in the catalystic elements of 6 x 6 to 10 x 10 mm size and flows parallel to the solid channel walls which have a thickness of about 1.5 mm. Basic material for the catalyst is TiO2 to which vanadium and/or tungsten as active material and a binding agent have been added. Catalysts are installed in layers in the reactor leaving a free space of 1-2 m between layers. Honeycomb elements are combined to form modules. This method allow for easy replacement of catalyst layers by means of a hoist or other lifting device.

4.1.2 Commercial Application in West Germany

Only a limited mount of commercial operating time has yet been achieved in Europe but many utility installations are in initial operation or under construction in West Germany. Commitment to SCR systems in West Germany for initial startup during the period 1986-1990, publicized as of July 1986 (22) are as per Table 4-1.

TABLE 4-1
PRINCIPAL SCR TECHNOLOGY SUPPLIERS

Catalyst Licensor	Approx. Aggregate MW(e)	Number of Installations High Dust	Cold End
Kawasaki	1,250	3	2
Mitsubishi	2,000	5	2
IHI	1,850	8	1
Babcock Hitachi	1,300	5	-
Norton	105	-	3
Other	810	3	-
Not announced/selected	1,860	8	-
Total SCR committed	9,175	32	8
SNCR committed	940	3	x

Approximately 30,000 MW(e) of large boiler capacity in North Rhine-Westphalia will be equipped with SCR by 1989 or 1990. By 1990 3700 MW(e) of NO_x removal systems, primarily SCR, will be installed in Baden-Wuerttemberg. In all, the boiler NO_x emission inventory throughout West Germany will ultimately be reduced by 0.7 million metric tons, principally by SCR (44).

4.1.3 Earlier Japanese Activity

In the work in Japan leading up to present applications in Germany the process manufacturers have routinely designed the SCR reactor for 80% NO_x removal and have often designed for 90% removal with a guarantee of 80%. The catalysts are also warranted for 1 to 2 years of lifetime. The predominant catalyst type that has been applied in Japan (8), and that is now being most extensively used in Germany is ceramic based type containing $TiO2$, $V2O_5$, and traces of heavy metals. Each of a multitude of catalyst layers that the flue gas contacts consists of single blocks of either honeycomb shaped ceramics or catalyst covered plates. Operational problems that have previously been encountered and addressed in commercialization of the technology in Japan are:

- o Plant efficiency reduction due to economizer tube removal
- o Catalyst erosion (and poisoning in the early installations)

- o SCR reactor plugging with ash
- o Plugging of the air preheater and induced draft fans with dust and ammonium bisulfate
- o Ammonia bypass leakage with a resulting contamination of the fly ash and the FGD wastewater
- o Difficulties with maintenance and accuracy of the NO_x and NH_3 instrumentation

4.1.4 Stringent Removal-Efficiency Requirements

While Japanese practice has established 80% NO_x removal in SCR as a generally practical maximum level to avoid significant ammonia leakage to the downstream air preheater and FGD system, permitting by some German provincial authorities in some applications calls for close to 90% SCR efficiency, which is of concern in view of the Japanese design philosophy. This includes a small installation of VEBA Kraftwerke at Knepper, 1986 initial startup, on a wet bottom boiler to reduce NO_x emissions to 200 mg/m^3. An SCR system starting up in 1986 on a dry-bottom boiler at Neckarwerke in Altbach, approximately 370 MW(e) SCR capacity, will also achieve a 200 mg/m^3 NO_x emission from the stack but treat only 80% of the total flue gas flow.

4.2 COMMERCIAL IMPLEMENTATION OF SCR TECHNOLOGY

4.2.1 Air Preheater Fouling

Through prior field study in Japan and more recent work in Germany (45), major efforts have been made to establish design criteria for the air preheater to make it compatible with common high-dust SCR operation upstream. (A similar concern would apply in connection with operation of rotary heat exchangers downstream of cold-side SCR.) In reducing flue-gas stream temperatures as low as 150°C to 230°C (300°F to 450°F) the air preheater causes excess NH_3 vapor from the SCR operation to react with water vapor and most of the SO_3 gas present to form the compounds ammonium bisulfate and ammonium sulfate. (The SCR reactor further enhances this formation due to the fact that the SCR catalyst converts approximately 1% of the flue gas SO_2 to SO_3, thereby essentially doubling flue-gas SO_3 concentration.) Ammonium sulfate vapor solidifies below 250°C (482°F) and ammonium bisulfate forms a liquid at a somewhat lower temperature. The latter solidifies at approximately 150°C (300°F). These compounds stick to fly ash and to the internal surfaces of the air preheater. It has also been found that the air preheater heating surfaces, so wetted and fouled, act like "fly paper" in collecting fly ash particles from the flue gas, further contributing to internal deposits and causing increased gas pressure drop. Fouling can be expected to be encountered when NH_3 concentration in flue gas downstream of SCR is as high as approximately 5 ppm. This can be expected when SCR is operated at NO_x removal efficiency substantially higher than 80% or, even at lower efficiencies when, toward

the end of the usable life of the catalyst charge, increased ammonia feed is used to maintain required NO_x removal efficiency. Nonetheless, the Germans emphasize that flue-gas SO_3 content is a more critical factor; at a specified NH_3 leakage rate it is the SO_3 content which determines whether there will be a serious rate of buildup of dry ammonium sulfate with liquid ammonium bisulfate on the air preheater heating surfaces. Based on field test experience in both Japan and Germany important criteria as follows have been established for design of deNO_x-compatible air preheaters (and gas-gas heaters for cold-side SCR as applicable):

- The heating surfaces must have a configuration that is easily cleaned by means of soot blowing.
- The cross-over of heating-element layers must be avoided in the area most likely to be affected by ammonium bisulfate deposition.
- Enameled heating elements should be used, particularly when SO_3 concentration is greater than 2 ppm.
- Highly efficient sootblowing devices must be used in order to limit outages.
- When SO_3 concentration is greater than 2 ppm need of provision for frequent off-the-line water washing of the air preheater must be anticipated; unlike rotary regenerative heat exchangers used to achieve flue gas reheat downstream of wet FGD, air preheaters downstream of SCR cannot be water washed on-line.

4.2.2 Difficulties in Retrofit Installation of SCR

Because of the large size of the SCR reactor, system retrofitting is a major engineering challenge, particularly in the case of high-dust applications, which require tie-ins to ductwork upstream of the air preheater. This is illustrated by a published report of the details of the 370 MW(e) SCR retrofit at Neckarwerke (Block 5) in Altbach recently put into operation. Although this unit is newly constructed, the SCR installation was in every sense a retrofit since it was not anticipated in the original plant design. Construction of the 460 MW(e) coal-fired unit began in 1982. In the spring of 1984 the boiler, air preheater and flue-gas ductwork were completed. The boilerhouse facade was already closed. Sections of the induced-draft fan were being manufactured. Initial operation of the plant was planned for mid-1985.

In the Spring of 1984, initial studies began for the installation of an SCR catalytic converter whereby the planned unit start-up date would be maintained and an emission value of 200 mg NO_x/m^3 would be achieved. The results of this study showed that it was possible to install an SCR system between boiler end and air preheater, with a flue gas volume of 1.1 million m^3/h (i.e. approximately 80% of the flue gas volume), and with two reactor bypass ducts, each for approximately 10% of the total flue gas volume. By arranging the converter between the boiler supports

and the load-bearing structure of the boilerhouse facade, it was possible to retain the exterior design of the boilerhouse. The reactor was designed for four converter levels and with one level for flow straightening blades. In the initial stage, only three converter levels were fitted. The design of the flue gas ducts, the mixing section for economizer bypass flow/residual flue-gas flow, the NH_3 feed section, the reactor are at the inlet side of the converter and the addition of the reactor bypass flow were carefully investigated by wind-tunnel tests. The configuration of the air preheater registers was altered, and the package length increased. While maintaining the induced-draft fan housing, the differential pressure developed could be increased by 20 mbar (8 in.W.G.) by alterations to the impeller. Figure 4-1 is a schematic illustration of the installation plan devised.

Subsequently the following retrofit alterations were carried out:

- Partial dismantling of the boilerhouse up to an elevation of over 40 meters
- Reinforcement of load bearing members in the boilerhouse area
- Dismantling of the flue gas ducts between boiler end and air preheater, and installation of the SCR reactor housing
- Installation of the reactor bypass ducts
- Installation of the economizer bypass, including opening of the boiler wall and installation of the ducts
- Installation of additional dust removal systems for the economizer bypass area and downstream of the reactor
- Installation of the ammonia supply system (support, distribution, injection)
- Alterations to the air preheater internals
- Alterations to the induced-draft system

With the benefit of careful planning and expedited shop work, and with construction activity planned to the last detail, installation of the major components (reactor, bypass ducts, economizer bypass) was completed in November 1984, after which the boilerhouse facade was closed again. Other work could thereby be performed so that trial operation of the unit was able to begin as scheduled in September 1985. Ammonia storage was completed by the end of October 1985. The catalyst was installed in November during a one-week shutdown. The first tests of NO_x emissions were performed in late November 1985.

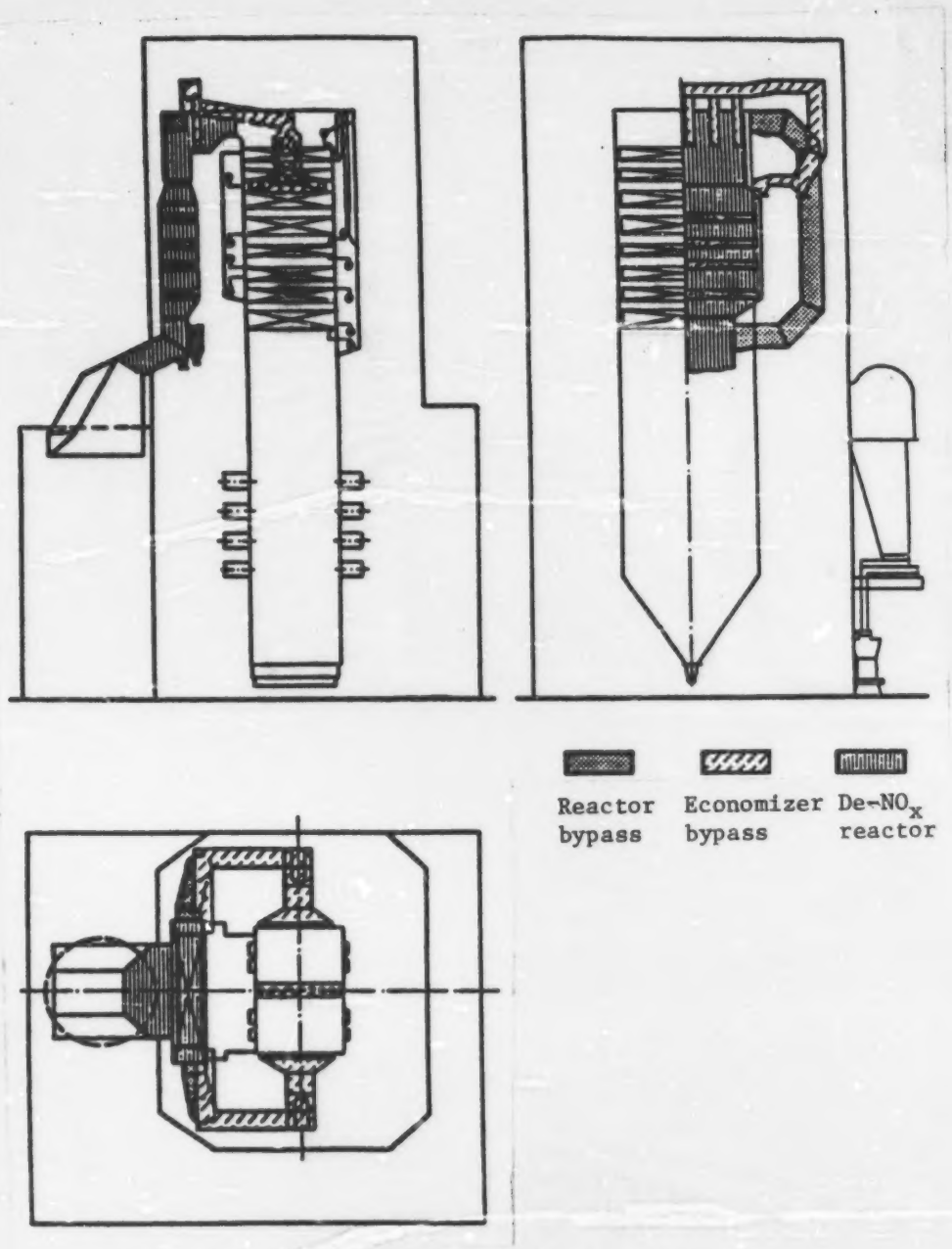


Figure 4-1. Cross-section of SCR system retrofit, side views/plan view.

4.2.3 Cold-Side SCR

In Japanese and European programs to retrofit SCR systems for flue-gas NO_x removal, physical plot-space limitations have in some instances prevented the tying in of the SCR reactor at the normal location, upstream of the air preheater i.e. in high-dust service at the "hot side" of flue gas desulfurization (FGD.) In such instances it may be necessary to use a "cold side", i.e. tail end, installation, adding SCR downstream of FGD, but connected so as to receive the FGD outlet gas after it has been heated to a suitable temperature, i.e. typically 320°C (608°F), for the catalyzed reduction of flue gas NO_x. The largest existing FGD-cold-side-SCR operation (downstream of wet FGD) is a 1,320,000 Nm^3/hr (820,000 scfm) 1979 installation, the equivalent of 330 MW(e), at an iron ore sinter furnace of Nippan Kokan KK at its Keihin Works in Japan. It utilizes a rotary regenerative heater followed by ammonia injection and an iron ore catalyst reactor operating at 390°C (734°F), to reduce a 200 ppm flue-gas NO_x concentration to 30 ppm. 1979 capital cost of the system installation is understood to be 6.7 billion yen, approximately 15 million DM, which is equivalent to approximately 20 million DM (1985), or roughly 60 DM per kW, somewhat higher than for a typical hot-side application.

Many cold side installations in West Germany announced to date (38) are small capacity with generally poor economics of scale. A municipal power plant, which is installing three 35 MW(e) cold-side SCR systems utilizing a cyclical operation of twin granular heatexchange beds in conjunction with feed of ammonia to a single catalyst chamber operating at 350°C (662°F) to reduce NO_x emission to 200 mg/Nm^3, is projected to have capital cost of 250 DM per kW (and a unit cost of 2.5 Pfg per kWh) (47). In a new boiler application of SCR, the greater apparent simplicity and economy of a hot-side installation may rule out use of a cold-side design.

However, the very substantial difference in total cost between hot-side and cold-side retrofit installations, typically, has largely to do with energy costs of the cold side technique that lead to substantial reheating of the flue gas above the water saturated temperature at which it exits the upstream FGD system. Cold-side SCR yields approximately 50°C (90°F) of flue gas reheat, and thus eliminates need for reheat facilities that would normally be included in the FGD installation. When an appropriate credit for this non-regenerative reheat is/can be given, the margin of cost difference between hot and cold side design is significantly reduced.

In addition, catalyst life and system reliability is expected to be better with cold-side operation. In an extensive field pilot test program (45) that began in early 1985 favorable reliability for tail-end system installations has been verified even with NH_3 leakage of approximately 5-10 ppm. No gas pressure drop increase has been experienced; SO_3 content of the flue gas is below 2 ppm and the flue-gas dust content is less than 50 mg/Nm^3, (0.04 lb/MM Btu.) Note, in conjunction with the discussion in Section 4.2.1., above, related to rotary heat exchanger fouling tendencies

by upstream SCR reactor operation, that this generally low flue-gas SO_3 concentration downstream of FGD is of major significance. Fullest consideration of this and other factors may lead to a broad new preference for cold-side SCR over high-dust SCR since (48):

- o A comparison of the tolerable operating regimes for cold-side and for high-dust SCR indicates that low flue-gas SO_2 content in cold-side operation makes it possible to use catalysts of considerably higher activity since the resulting higher rate of SO_3 formation in the SCR reactor can be tolerated without any dramatic increase in formation of the undesirable ammonia-sulfur compounds. (Ammonia emission or slip in high-dust configurations must be kept at a low level. According to Japanese experience less than 5 ppm is required in order to achieve a 6000 hour cleaning interval for the removal of ammonium bisulfate from the air preheater.)

- o Cold-side SCR design technology development may be expected to lead to very low SCR operating temperature, perhaps no more than 100°C, in an economical system arrangement that would use a simple steam coil heater in lieu of a rotary regenerative heat exchanger, and handles only approximately half the actual flue gas flow volume of a high-dust SCR system.

- o Low flue-gas SO_3 concentration in a cold-side system makes it possible to tolerate substantially higher ammonia leakage. In addition a low flue-gas particulate concentration permits use of catalysts of a small geometric pitch having a higher specific surface. These factors work together to make possible a more compact reactor design.

- o In cold-side installations the SCR reactor temperature is maintained at an optimum level for the NO_x reduction independently of boiler load and without need for provisions such as economizer bypassing.

- o As determined in West German pilot plant tests, catalyst activity/life in high-dust SCR operation is substantially shortened in wet bottom (slag-tap) boiler service due to a characteristically high alkali metals content of the fly ash.

- o In use of high-dust SCR operation in typical dry bottom boiler service the high concentration of dust reaching the catalyst erodes it and, at the same time, the flow channels in the catalyst must be large enough to prevent the catalyst from becoming plugged up. Erosion will continuously form new surfaces and this calls for highly efficient gas flow distribution. Catalyst life is less than half that of a cold-side SCR installation.

4.2.4 Integrated Air-Preheater/SCR-Reactor Design

To minimize the cost penalties for installing and operating cold-side SCR at large coal-fired electric utility plants when plot-space limitations make it necessary to do so, or other reasons call for it, more economical system designs are anticipated that combine the regenerative heat exchanger and the SCR reactor into a single integrated assembly. Engineering and operation of such future integrated system designs is expected to include use of economical coal-based high-pressure steam (in lieu of fired clean fuel) for the augmenting of flue-gas feed preheat upstream of SCR, and the advantageous use of a plate type (rather than honeycomb-grid type) catalyst configuration compatible with the heat exchanger internals.

Air preheater manufacturing interests in Germany have extensive field programs underway to develop an attractive SCR system design, (45) the De-NO_x Air Preheater, (or a De-NO_x Gas-Gas-Heater), for moderate NO_x removal efficiencies in either hot or cold side service. See Figures 4-3 and 4-6 illustrating integrated system designs as contrasted with conventional high-dust and cold-side SCR installations depicted by Figures 4-2, 4-4, and 4-5.

Since the regenerative heat exchangers have a surface area comparable in size to that of a typical SCR reactor, the basic idea of the development is to integrate the catalyst into the heating surface of the already available Lungstrom-type air preheater and thereby avoid need for cost and space of a separate SCR reactor. The supplier is concentrating on the optimum utilization of the element height despite the axial temperature variation in the basket, and expects efficient operation of the systems after the initial "teething" problems have been solved. Despite NO_x removal efficiencies of 60% and higher in early small-scale field tests an initial large scale, 150 MW(e), test in late 1985 demonstrated far less. Further new small scale testing is underway in this major developmental program seeking to overcome present obstacles.

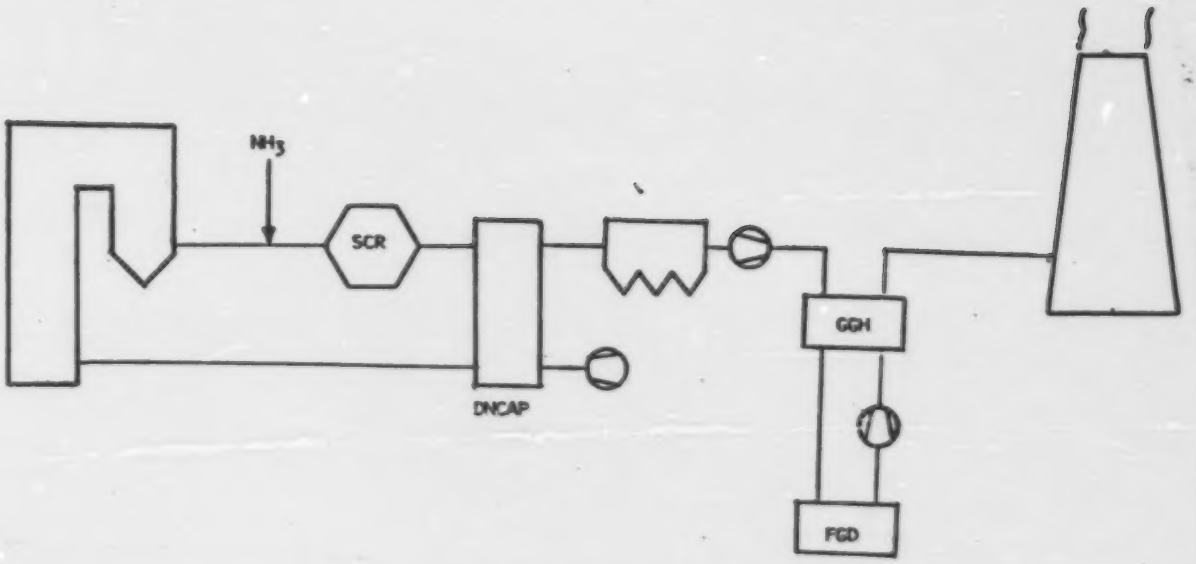


Figure 4-2. Conventional high-dust SCR application.

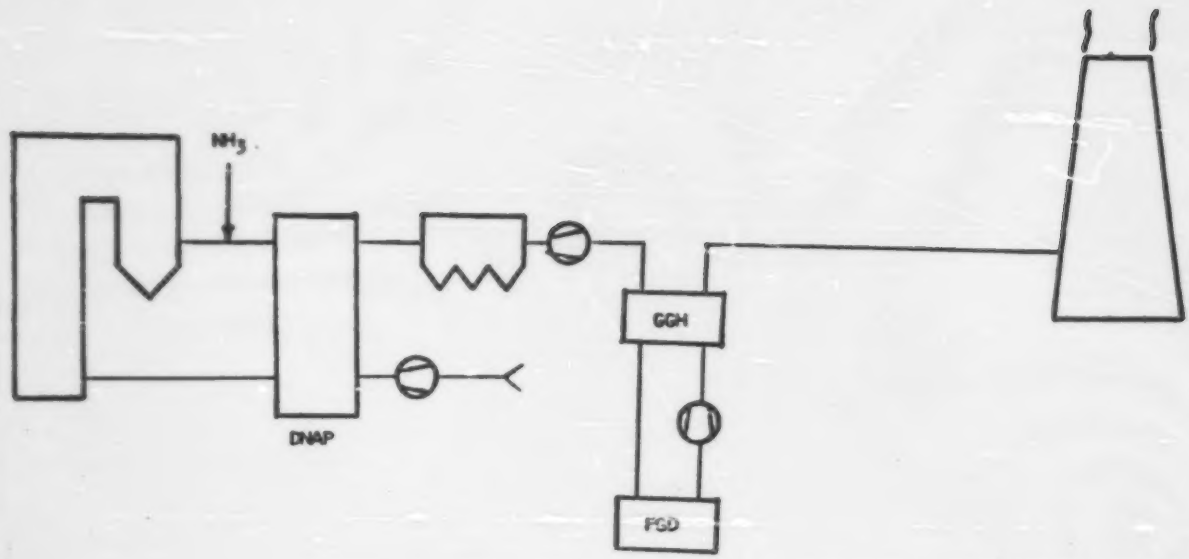


Figure 4-3. Integrated air preheater/SCR-reactor (high dust).

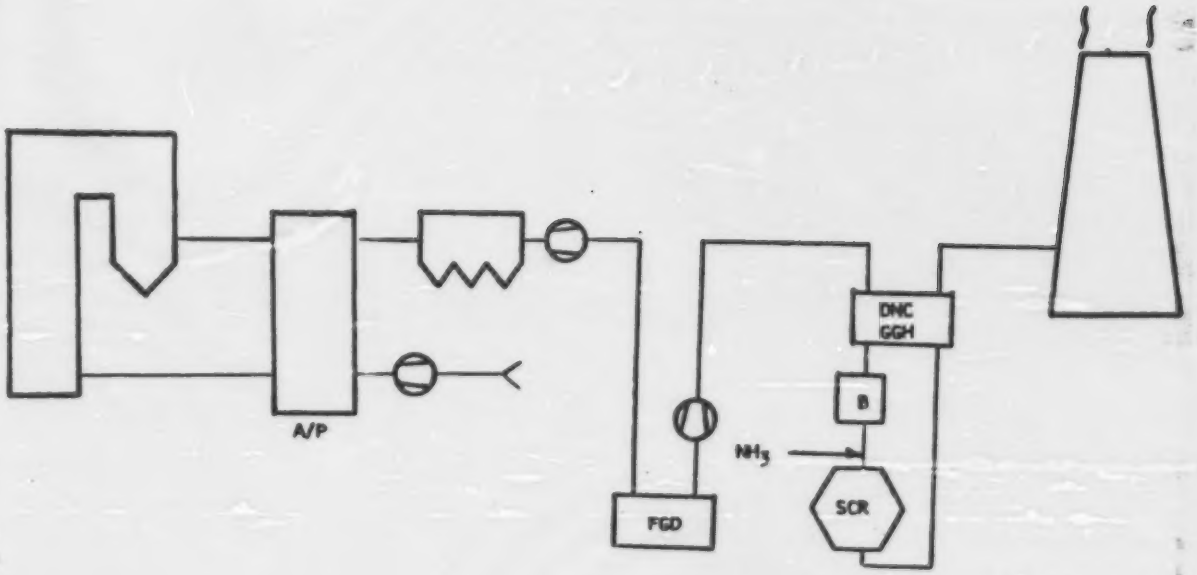


Figure 4-4. Cold-side SCR (new boiler application).

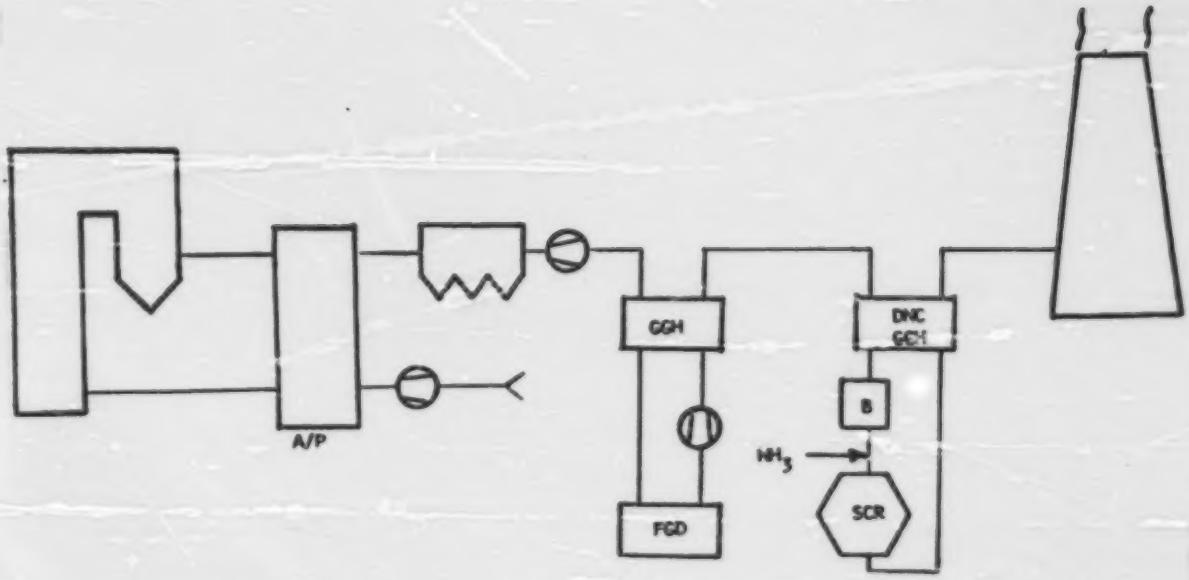


Figure 4-5. Cold-side SCR (existing boiler/FGD application).

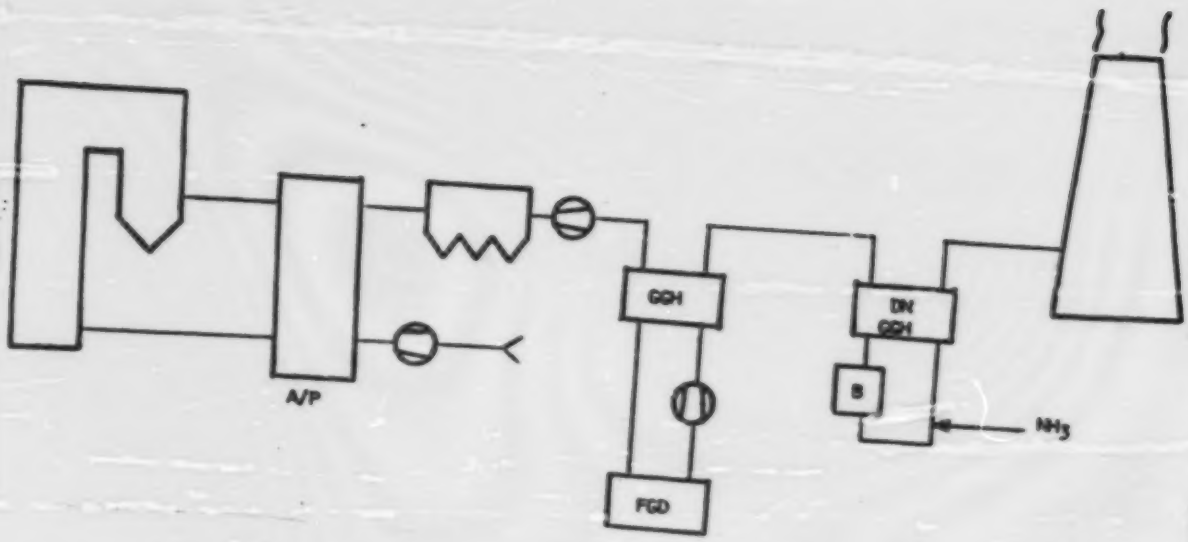


Figure 4-6. Integrated heat exchanger/SCR-reactor (cold-side).

SECTION 5

OTHER POST-COMBUSTION DE-NO_x AND SO_x/NO_x REMOVAL PROCESSES

5.1 ACTIVATED CARBON (COKE) SO_x/NO_x PROCESS

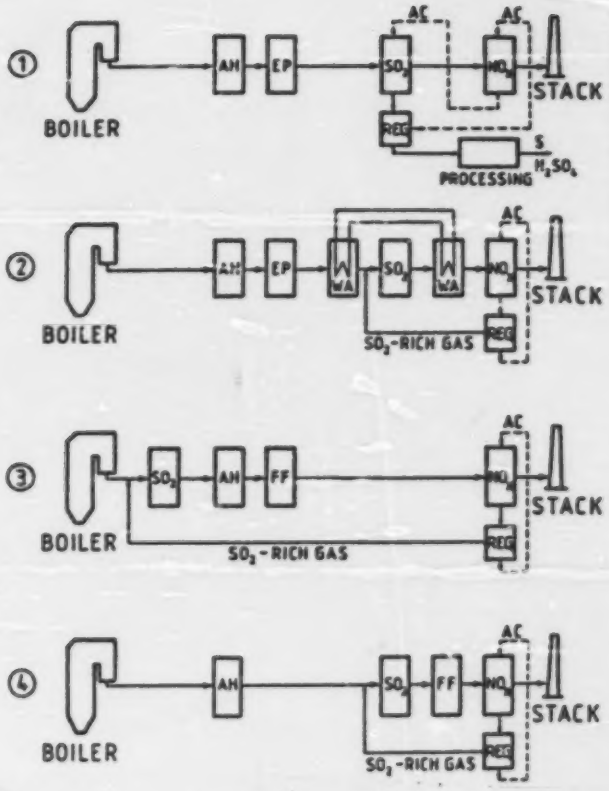
This dry removal technology has been under development in West Germany by Bergbau-Forschung GmbH, the central research center of the German bituminous coal mining industry, for FGD since 1965, and since 1979 has been tested and demonstrated as a simultaneous SO_2/NO_x removal process (49). A commercial SO_x/NO_x installation of approximately 50 MW(e) size has been in operation in Japan since 1985.

The process typically uses activated carbon (coke) at 120°C (250°F) in a moving-bed adsorber system for SO_2 removal, with high-temperature coke regeneration in a desorber, which produces a rich-SO_2 off-gas that will be converted into commercial sulfuric acid. The system uses ammonia reagent in a second bed, downstream to also collect NO_x at high efficiency. A closed conveyor system cycles the coke between the adsorbers and the desorber. The operating temperature range of the process is 90° to 150°C (194 to 302°F).

A 237 MW(e) SO_x/NO_x removal installation by Bergbau-Forschung/Uhde meeting SO_2 and NO_x emission control requirements of the 1983/1984 legislation begins operation in West Germany near the end of 1986 at a lignite-fired unit. Design SO_2 removal efficiency is greater than 95% and design NO_x removal efficiency is greater than 73%. As illustrated in Figure 5-1, the dry NO_x removal capability can be applied either in conjunction with SO_2 removal by activated carbon or as a cold-side SCR step downstream of conventional wet or dry FGD, in many instances without need or justification for heat exchanger equipment to increase inlet flue gas temperature. Combustibility of coke is a concern from a safety standpoint.

5.2 ABSORPTION-REDUCTION SCRUBBING

A 750 MW(e) Saarberg-Hoelter-Lurgi usable-gypsum producing, lime scrubbing installation under construction for 1987 startup is designed to use a ferrous-based EDTA chelate to gain simultaneous high-efficiency SO_2 and NO_x removal in a wet absorption-reduction mode (24). Although little information has been published or disclosed it is known (50) that the process is based on the principle of catalytic reduction of NO (nitric oxide) by SO_2 in the form of sulfite ions, forming mainly elemental nitrogen and sulfate. Chemical reducing conditions in the scrubbing medium are essential in order to retain the solved iron in the catalytically active, bivalent (ferrous) form. A slipstream of the scrubber liquor is drawn from the absorber, reactivated by solids precipitation using slaked lime reagent and returned to the scrubber. The precipitate, which contains



1. Simultaneous SO_2/NO_x removal.
2. NO_x removal downstream of wet FGD.
3. NO_x removal downstream of dry additive FGD.
4. NO_x removal downstream of desulfurization by spray drying process.

AH - Air preheater
FF - Fabric filter
EP - Electrostatic precipitator
WA - Heat exchanger for reheating

Figure 5-1. Activated carbon processes for SO_x/NO_x removal.

a large amount of calcium sulfite, is dewatered, suspended or solved in sulfuric acid, and oxidized with compressed air to form the gypsum by-product. Minor production of unique tramp sulfur/nitrogen and sulfur compounds formed in the catalyzed chemically-reducing environment of the scrubbing medium is purged by precipitation/crystallization from a blowdown stream followed by calcination to form recyclable/disposable chemical forms.

5.3 ELECTRON BEAM PROCESS

This emerging process technology for high-efficiency simultaneous SO_x/NO_x removal using high-energy radiation from 800 kV electron beam accelerators to ionize and excite molecules of SO_x and NO_x in flue in the presence of ammonia reagent has been under development in Japan since 1970 and also in the U.S.A. as recently as 1985. A commercial byproduct, 90% ammonium sulfate and nitrate, useful as a fertilizer or general soil conditioner, is formed. Electrons in the energy range used for processing of flue gas do not produce any radioactivity.

Another process (51) based on the use of a low-energy electron beam accelerator (300 kV unit, 90 kW) is (since December 1985) currently being tested in a field pilot plant in West Germany. This process development unit uses the "electrocurtain" electron beam machine produced by Energy Sciences International (Charmilles International in Europe) with energy of 300 kV and 100 mA current. Most recent study and evaluation indicates that this voltage level is adequate to achieve penetration of electrons in flue gases. The advantage of using lower energies, especially below 500 kV, is that these machines usually come in self-shielded configurations and no additional shielding is required, thereby significantly reducing the cost of construction and probably also space requirements.

The main problem to be solved as far as these electron beam accelerators are concerned is the availability of low energy but high power units. Presently running PDUs (process development units) are of a size corresponding approximately to that required by 10 MW power generating plants. Equipping large, i.e. 500-1000 MW power plants would require a large number of accelerators of existing design, each with a power rating of about 100 kW. 500-900 kW units may be required for large power plants. According to manufacturers, these units are within the reach of the present state of accelerator technology.

5.4 SOLINOX PROCESS

This simultaneous SO_x/NO_x removal process of Linde AG (52) uses the regenerable wet scrubbing medium, tetraethyleneglycoldimethylether, a non-toxic commercial solvent/refrigerant, to physically dissolve and collect SO_2 for subsequent recovery as commercial sulfuric acid or liq. SO_2. Before FGD the raw flue gas is cooled and pre-purified by a combination of regenerative heat exchange with the clean stack gas followed by pre-scrubbing with water. NO_x removal is achieved in a cold-side SCR system operating at 300°C to 350°C (572°F to 662°F) that

utilizes granular-bed regenerative heat exchangers. The FGD portion of the process has been applied to several industrial SO_2 emission sources in Europe in the size range equivalent to 20 to 30 MW(e) at raw-gas SO_2 concentrations in the range of 8,000 to 14,000 ppm. As described in Section 4.2.3, above, three (3) 35 MW(e) installations of the deNOx portion of the process are under construction at a municipal power plant in West Germany. The systems are designed for a minimum of 80% NO_x removal.

5.5 CAUSTIC SCRUBBING

A retrofit wet limestone FGD system augmented by post-scrubbing with caustic liquor will go into service at the large North Munich coal-fired power plant in 1989 with guaranteed emission limits of 25 mg SO_2/Nm^3 (9 ppm) and 100 mg NO_2/Nm^3 (50 ppm).

5.6 WET GAS SULFURIC ACID PROCESS

Haldor Topsoe (53) has developed the Wet Gas Sulfuric Acid Process, which is particularly applicable to very high-strength SO_2 emission sources such as ore roasters. Raw flue gas is heated regeneratively, (primarily by heat recovered from the process) to 420°C, and the SO_2 is converted to SO_3 which in turn is cooled and hydrated to form 96% sulfuric acid by-product.

SECTION 6

ESTIMATED COSTS FOR SO_2 AND NO_x CONTROL

6.1 FLUE GAS DESULFURIZATION

The West German Federal Environmental Agency (Umwelbundesamt) has published (54) results of its study of stack gas cleaning costs based on information from system suppliers and also from field experience with systems either in operation or under construction in that country. Table 6-1 tabulates these reported costs (1985 Deutsche Marks, i.e. DM, 1DM = approximately U.S. $0.50) for a grass roots 700 MW(e) installation with 6000 annual hours of full-load operation in low sulfur bituminous coal service (designed for 95% SO_2 removal and regenerative reheat) with comparable values derived by a spokesman for European boiler owners (38). Differences between cost levels indicated are mainly the result of forecasted differences in capital depreciation rate and in prices and consumption of raw materials, utilities and other variable operating costs. See Table 6-2.

With a unit cost for FGD of approximately 1 Pfg/kWh, (1985 DM basis, 100 Pfg = 1 DM), and with a currency exchange rate of approximately 1 DM = U.S. $0.50, it could be judged that West German FGD cost equates to 5 mils (U.S.) per kWh, a value substantially lower than that reported in U.S.A. for comparable U.S. applications. Such cost conversion is believed to be misleading since the "buying power" of currency in one country does not necessarily match that of a currency-exchange-equivalent in another country.

TABLE 6-1
COMPARISON OF ALTERNATIVE DATA SOURCES FOR COSTS FOR
700 MW(E) WEST GERMAN GRASS ROOTS FGD FACILITY

	West German Government (Umweltbundesamt)	European Boiler Owners (VGB)
Capital Cost, MMDM	140	140
(DM/kW)	(200)	(200)
Annual Costs, MMDM		
Investment	26.0	30.8
Operation and Maintenance	9.1	12.78
Total	35.1	43.58
Specific Costs, Pfg/kWh	0.84	1.04

TABLE 6-2
BASES FOR 700 MW(E) FGD FACILITY COST ESTIMATES

	West German Government (Umweltbundesamt)	European Boiler Owners (VGB)
Period of depreciation, years	15	10
% annual charges for capital	18.5	22
Annual maintenance cost, % of capital investment	4	4
Number of shift operators	1	2
Limestone consumption, ton $CaCO_3$ per ton SO_2 removed	1.56	1.60
Delivered price of limestone, DM per metric ton $CaCO_3$	35	40
Power consumption, MW(e)	7	10.5
Power cost, DM per kWh	0.15	0.15
Makeup water cost, DM per m^3	1	1

6.2 NO_x REMOVAL

In a manner similar to that employed in Section 6.1, above, for FGD costs, 1985-DM estimates are presented in Tables 6-3, 6-4, 6-5, and 6-6 for reported costs for a grass roots 700 MW(e) SCR installation with 6000 annual hours of full-load operation in low sulfur bituminous coal service (designed for a nominal 85% NO_x removal). Note that SCR catalyst is treated as an operating expense, and capital cost values do not include the appreciable cost, i.e. approximately 50 DM per kW or more, of the initial catalyst charge. Differences between cost levels indicated are mainly the result of forecasted differences in capital depreciation rate and in catalyst replacement costs. See Table 6-7. By contrast with the costs reflected in Table 6-3 for a grass roots high-dust installation on a very large, dry-bottom boiler, a retrofit high-dust application at a similar 460 MW(e) boiler at Neckarwerke (see Section 4.2.2, above) cost 65 million DM (141 DM per kW) including cost of catalyst (46), and, assuming 10,000 to 12,000 hours catalyst life, specific (unit) cost is approximately 0.9 Pfg/kWh. (This first large-scale operating SCR installation in Europe was partially funded in the amount of 15 million DM by the West German Federal Environmental Agency and is expected to serve as a commercial retrofit demonstration plant for the introduction of SCR technology in that country.)

TABLE 6-3
COMPARISON OF ALTERNATIVE DATA SOURCES FOR COSTS
FOR 700 MW(E) WEST GERMAN GRASS ROOTS HIGH-DUST
SCR FACILITY FOR DRY-BOTTOM BOILER

	West German Government (Umweltbundesamt)	European Boiler Owners (VGB)
Capital Costs, MMDM (DM/kW)	32.4 (46.3)	33 (47.1)
Annual Costs, MMDM		
Investment	6.0	7.26
Operation and Maintenance	12.4	24.66
Total	18.4	31.92
Specific Costs, Pfg/kWh	0.44	0.76

TABLE 6-4
700 MW(E) WEST GERMAN GRASS ROOTS COSTS FOR
COLD-END SCR FACILITY FOR DRY-BOTTOM BOILER

	West German Government (Umweltbundesamt)	European Boiler Owners (VGB)
Capital Costs, MMDM (DM/kW)	42.7 (61.0)	36 (51.4)
Annual Costs, MMDM		
Investment	7.9	7.92
Operation and Maintenance	22.6	34.46
Total	30.5	42.38
Specific Costs, Pfg/kWh	0.73	1.01

TABLE 6-5
700 MW(E) WEST GERMAN GRASS ROOTS COSTS FOR
HIGH-DUST SCR FACILITY FOR SLAG-TAP BOILER

	West German Government (Umweltbundesamt)	European Boiler Owners (VGB)
Capital Costs, MMDM	32.4	33
(DM/kW)	(46.3)	(47.1)
Annual Costs, MMDM		
Investment	6.0	7.26
Operation and Maintenance	19.8	35.02
Total	25.8	42.28
Specific Costs, Pfg/kWh	0.62	1.01

TABLE 6-6
700 MW(E) WEST GERMAN GRASS ROOTS COSTS FOR
COLD-END SCR FACILITY FOR SLAG-TAP BOILER

	West German Government (Umweltbundesamt)	European Boiler Owners (VGB)
Capital Costs, MMDM	42.7	36
(DM/kW)	(61.0)	(51.4)
Annual Costs, MMDM		
Investment	7.9	7.92
Operation and Maintenance	28.3	42.23
Total	36.5	50.15
Specific Costs, Pfg/kWh	0.86	1.19

TABLE 6-7
BASES FOR 700 MW(E) SCR FACILITY COST ESTIMATES

	West German Government (Umweltbundesamt)	European Boiler Owners (VGB)
Period of depreciation, years	15	10
% annual charges for capital	18.5	22
Annual maintenance cost, % of capital investment	4	4
Number of shift operators	0	1
Catalyst demand, m^3 per 100 MW(e):		
Slag-tap furnace	130	180
Dry-bottom furnace	90	126
Catalyst space velocity, $hour^{-1}$		
Slag-tap furnace	2,500	1,750
Dry-bottom furnace	3,500	2,500
Catalyst lifetime, years		
High-dust	3	2
Cold-side	5	3
Catalyst price, DM per m^3	40,000	40,000

Cold-end system cost estimates are substantially higher than for high-dust because of the inclusion of regenerative heat exchange equipment to boost the FGD outlet gas temperature, and because of added energy required to attain SCR operating temperature. No credit is given in this and similar evaluations for the increased stack temperature resulting from the use of augmental energy input in cold-side SCR operation. SCR installations for slag-tap boilers are more costly than for dry-bottom boilers because of the higher operating costs associated with characteristically higher SCR-inlet NO_x concentrations (e.g. 1,300 to 1,800 $mgNO_2/Nm^3$) anticipated for slag-tap installations than those expected for dry-bottom installations, (e.g. 500 to 800 $mgNO_2/Nm^3$.)

As indicated in Section 6.1, above, conversion of costs in European currency to corresponding values in U.S. currency would be expected to be misleading because of potential differences from one country to another in "buying power" of otherwise equivalent amounts of currency.

SECTION 7

OTHER EUROPEAN COUNTRIES

Led by the West German activities that began in 1983, extensive programs are underway throughout Europe to address the acid precipitation problem with major reductions in SO_2 and NO_x emission inventories.

7.1 THE NETHERLANDS

Under pending Dutch law high-efficiency FGD is required for all coal-fired boilers larger than 300 MW(t). Large retrofitted FGD systems comprising approximately 2,720 MW(e) at four power plants are in operation or under construction, all designed for usable gypsum production using wet limestone FGD for operation with 1.5% sulfur coal-firing. See Table 7-1. A broad acid rain control regulation (Tables 7-2 and 7-3) modeled after current West German legislation is expected to be passed in 1986, and in the interim has been used for SO_2 and NO_x emission control guidelines by the licensing authorities (55).

TABLE 7-1
FGD SYSTEMS SUPPLIED IN THE NETHERLANDS

Supplier	Aggregate MW(e)	No. of Install.
Chemico/Esmil (GEESI)	1,240	3
Bischoff/Comprimo and Tebodin	1,480	3

7.1.1 SO_2 Emissions

With the exception of one initial Chemico installation, which went into service in 1985, all FGD installations are single-loop in-situ forced oxidation designs. This early installation uses a prescrubber and separate gypsum oxidation vessels, and will in 1987 be modified to eliminate these components and convert the system to single-loop in-situ forced oxidation operation. Except for one installation that uses hot exhaust gas from a gas turbine generator for flue gas reheat all FGD installations in The Netherlands utilize rotary heat exchangers for regenerative reheat.

The Bischoff installations, initial startup in 1987 and 1988, are all on large units that are being converted from oil and gas to coal-firing and are designed for 88 to 90% SO_2 removal. As in the case of the West German Bischoff installation on the North Sea (Wilhelmshaven), one of its Netherlands installations will use sea water for FGD makeup water. The GEESI installations are for 90% SO_2 removal.

TABLE 7-2
DRAFT SO_2 EMISSION STANDARDS FOR FUEL BURNING PLANTS IN THE NETHERLANDS

Fuel	New Installations	Existing Installations
Coal	Over 300 MW(t): 400 mg/m^3; 85% efficient FGD	Over 300 MW(t): 0.8% S: and for installations with an indefinite lifetime, the same as for new installations
	Under 300 MW(t): 700 mg/m^3	Under 300 MW(t): 1.2% S
Oil	Over 300 MW(t): 400 mg/m^3; 85% efficient FGD	Over 300 MW(t): 400 mg/m^3; 85% efficient FGD for installations with an indefinite lifetime Other: 1,700 mg/m^3
	Under 300 MW(t): 1,700 mg/m^3	Under 300 MW(t): 1,700 mg/m^3
Gas	Refinery Gas: 35 mg/m^3	Refinery Gas: 35 mg/m^3 (1/1/1986)
	Oxygas: 35 mg/m^3	Oxygas: 35 mg/m^3 (1/1/1987)
	Blast Furn. Gas: 200 mg/m^3	Blast Furn.: 200 mg/m^3 (1/1/1987)
	Coke Oven Gas: 800 mg/m^3	Coke Oven gas: 800 mg/m^3 (1/1/1987)

TABLE 7-3
DRAFT NO_x EMISSION STANDARDS FOR FUEL BURNING PLANTS IN THE NETHERLANDS

Fuel	New Installations		Existing Installations
	1/1/1986	1/1/1988	
Coal	Over 300 MW(t): 800 mg/m^3	400 mg/m^3	Over 300 MW(t): Pulverized fired: 1100-800 mg/m^3 Other: 1000 mg/m^3 (1/1/1989)
	Under 300 MW(t): 800 mg/m^3	500 mg/m^3	Under 300 MW(t): Not applicable
Oil	450 mg/m^3	300 mg/m^3	700/450 mg/m^3
Gas	350 mg/m^3	200 mg/m^3	500/350 mg/m^3

Officials in The Netherlands have investigated potential FGD gypsum quality (40) and expect to be able to market the gypsum to the Dutch or foreign gypsum industry. Future use of other than gypsum-producing systems is being evaluated, especially dry scrubbing (spray-drying). An extensive program to develop applications for the spray-drying absorption product is under way including (56) use of spray-dryer waste and fly ash mixtures as a partial substitute for sand in the manufacture of sand-lime bricks common to The Netherlands.

7.1.2 NO_x Emissions

The NO_x emission levels in the draft emission standards (Table 7-3) will, even for new boilers, enable the use of combustion modifications and low-NO_x burners to meet NO_x control objectives.

Three tangentially fired coal-natural gas boilers are under construction. The boiler volume is increased by 20-25% compared to the conventional design and modified burners with overfire air will be applied. A 270 g/GJ (approximately 750 mg NO_2/Nm^3) emission limit is guaranteed by the boiler supplier over a broad range of coal analyses.

Ten existing natural gas/oil-fired boilers will be equipped with gas turbines. Exhaust from the gas turbines will be used as boiler combustion air. Besides an increase in boiler efficiency a considerable reduction of the NO_x emission is expected due to the low oxygen content of combustion air, in addition to the reburning effect on turbine-generated NO_x.

A demonstration of "in-furnace-reduction" is in preparation for a 185 MW(e) gas/oil-fired boiler. This is seen as an intermediate step towards application of this technology for new coal-fired boilers.

Finally, a fully government-funded demonstration of SCR technology for Dutch coal-fired power plant conditions is in progress. A 65 MW(e) unit will come on stream at the end of 1986. Design NO_x removal is 80%, with a maximum ammonia-leakage of 5 ppm. Technology is by Japanese catalyst licensor, Mitsubishi.

7.2 AUSTRIA

Based on the requirements of the Ministry of Building and Construction stated in the Steam Boiler Emissions Law (DKEG) many FGD and deNO_x projects are completed or underway. Through use of FGD, reductions in sulfur content of fuel oil and diesel oil, and switching from oil to natural gas fuel, annual SO_2 emissions were reduced in the period 1980 to 1985 from 354,000 metric tons to 180,500 metric tons. Winter season ground-level air monitoring in the center of four major cities, including Vienna, indicates that SO_2 concentration decreased from 30 to 60% during this period. Annual NO_x emissions, 65% of which is from mobile sources, remained approximately constant at 216,000 metric tons during this same time span (57).

The national government drafted a technology-forcing amendment to DKEG in March 1986 (see Table 7-4), applicable to boilers over 10 MW(t) = 3.7 MW(e), calling for major retrofit activity to reduce SO_2 emissions from existing units over a five-year period to levels already required for new boilers, and to reduce NO_x emissions over a two-year period by use of primary (combustion modification) measures. (Additionally, existing CO emissions must be reduced to 250 mg/Nm^3, i.e. 200 ppm, and existing particulate emissions for boilers above 100 MW(t) must be reduced to 30 mg/Nm^3, i.e. 0.025 lb/MMBtu heat input.) Note that the draft SO_2 emission limit for existing bituminous coal-fired boilers larger than 300 MW(t), approximately equivalent to 110 MW(e), is 150 mg/Nm^3, (equivalent to 53 ppm), or 90% SO_2 removal, whichever is more stringent.

TABLE 7-4
PROPOSED SO_2 AND NO_x EMISSION STANDARDS
FOR BOILERS IN AUSTRIA

	SO_2 Standard (90% Removal or mg/m^3, below)		NO_x Standard (mg NO_2/m^3)
MW(t)	Lignite	Bituminous	
10-50	1200	400	400
50-100	500	200	300
100-150	350	200	300
150-300	350	200	300
over 300	300	150	150

7.2.1 SO_2 Emissions

Approximately 2000 MW(e) of wet FGD is in operation or under construction, almost all usable-gypsum-producing lime/limestone installations, generally equipped with prescrubbers for segregated collection of HCl and residual particulate matter. Retrofit installations include two wet lime/limestone system totaling 370 MW(e) and one Wellman-Lord system with scrubber size equivalent to 163 MW(e). In one application tubular-type regenerative flue-gas reheat facilities are provided, and in essentially all others rotary regenerative reheat equipment is used.

The first commercial system worldwide for boiler limestone injection went into operation at Voitsberg power plant, Unit 2, 65 MW(e), in lignite-fired service in 1983 (11). This retrofit installation achieves 57% SO_2 removal. Three additional limestone injection systems aggregating 440 MW(e) have been purchased. This includes a pilot plant installation on a boiler in bituminous coal service being derated to 80 MW(e) for SO_2 control by limestone injection that will begin initial test operations at 80% SO_2 removal in 1987. An 80%-efficient limestone injection system is scheduled for initial operation in 1986 on a 110 MW(e) lignite-fired boiler.

A 133 MW(e) circulating fluid bed boiler has been under construction at Gratkorn. This unit, the largest in Europe, will fire lignite and combustible wastes from pulp and paper production. Emission limits are 400 mg SO_2/Nm^3 (140 ppm) and 300 mg NO_x as NO_2/Nm^3 (150 ppm) but local authorities intend to lower the limit for SO_2 to 200 mg/Nm^3 (70 ppm) by 1988, requiring increased grinding and feed of limestone reagent.

7.2.2 NO_x Emissions

Coal-fired units aggregated 1500 MW(e) have been retrofitted with combustion modifications including overfire air and low-NO_x burners under the impetus of DKEG to gain reductions in NO_x emissions. Based on use of technology by licensees Babcock Hitachi and Mitsubishi retrofit SCR installations designed for 200 mg NO_2/Nm^3 outlet emission will be in service by 1986 on three bituminous coal-fired units aggregating 925 MW(e). Additional SCR of 800 MW(e) capacity, primarily by retrofit, is scheduled for later application (1987 to 1990 initial startup) in oil- and gas-fired service. In 1985, SCR pilot plant operations using technology of licensees IHI and Babcock Hitachi began at a lignite-fired power plant to make comparative tests of ceramic vs. plate type catalyst for retrofit application in a 330 MW(e) installation scheduled for initial operation in 1987.

7.3 SWEDEN

Sweden has been severely impacted by acid precipitation for many years and has taken major steps to reduce its substantial emissions (58). Approximately 20,000 lakes and 90,000 km (56,000 miles) of water-courses are affected by acidification due to the discharge of sulfurous and nitrogenous oxides. Groundwater, land and forests have also been found to be affected. At the same time between 80 and 90% of sulfurous precipitation in Sweden comes from foreign sources. As a result of a national program annual sulfur dioxide emissions in Sweden have decreased by more than two-thirds from a peak value of close to 1 million metric tons in the early 1970s. Sweden aims for a reduction by 1995 to an annual SO_2 emission inventory of approximately 175,000 metric tons or less, a level 65% less than that in 1980. The annual NO_x emission inventory peaked at approximately 325,000 metric tons in 1980. This amount is expected to decrease in the next ten years due to the introduction of stricter exhaust emission control requirements on motor vehicles as well as measures to restrict nitrogen oxides emissions from stationary sources. The aim of the government is to reduce NO_x emissions by 1995 to a level 30% less than the 1980 peak.

7.3.1 SO_2 Emissions

Principal restrictions on new and existing emissions include a 1% limit on oil sulfur content and the equivalent maximum SO_2 emission, 0.24 gS/MJ (240 g S/GJ), equivalent to 1400 mg SO_2/Nm^3, for use of other fuels.

A 0.1-0.17 gS/MJ (570 to 970 mg SO_2/Nm^3) emission-limit guideline applies to new or modified emission sources of size less than 400 annual metric tons sulfur such as industrial boilers, district heating and cogeneration plants, the magnitude of the emission limit varying with geographic location and other factors. Several 20-40 MW(t) circulating fluidized-bed boilers utilize limestone addition for SO_2 emission control when firing coal (59).

An emission-limit guideline of 0.05 to 0.1 g S/MJ, i.e. 290 to 580 mg SO_2/Nm^3, equivalent to 0.23 lb SO_2/MMBtu heat input applies to emission sources larger than 400 annual metric tons sulfur. This has led to installation of dry-scrubbing type FGD for six district steam-heating plants. As of 1982 (60) two new 500 MW(e) coal-fired units were anticipated to be in operation by 1992, (together with 15 to 25 new coal-fired district heating plants in the size range 150 to 600 MW(t), a few of which are already in operation with dry-scrubbing type FGD). It is now expected (59) that when a new large coal-fired unit has to be built (to compensate for the expected permanent closing down of nuclear power plants as dictated by national referendum) governmental authorities will require an emission limit both for SO_2 and NO_x at least as low as that which applies in West Germany at that time.

By the end of 1986 an aggregate of 1280 MW(t), i.e. approximately 470 MW(e), of dry-scrubbing FGD will be in operation in low-sulfur coal service at the six heating plants noted above. Design removal efficiencies are generally in the range of 70 to 80% to achieve a 0.1 g S/MJ (570 mg SO_2/m^3) limit value. Most of these installations (59) include an electrostatic precipitator precollector, which will help ensure a maximum potential for utilization of the FGD solid waste. FGD operations at two of the plants began in 1982 and 1983 and has been quite good (59).

The Swedes have shown that SO_x emissions of stoker-fired boilers can be reduced by the feeding of limestone or dolomite above the burning fuel. This has been demonstrated at a plant comprising two 125 MW(t) boilers where it has been possible to achieve an SO_2 removal efficiency of 60-70% with an emission limit of 0.1 g S/MJ (570 mg SO_2/m^3). The removal efficiency depends on the Ca/S molar ratio, the temperature in the furnace and the retention time. The capital costs are 100 Swedish Kroner/kw(t), i.e. approximately 270 SK/kw(e). (1 SK = approximately U.S. $0.17.) This is approximately 35 to 50% of the reported capital cost of Swedish dry scrubbing installations, above, of comparable capacity.

7.3.2 NO_x Emissions

In approximately 1985 concern for NO_x emissions substantially increased and the government proposed an NO_x emission limit of 0.1 g NO_2/MJ (100 g/GJ), equivalent to 285 mg NO_2/m^3, (approximately 140 ppm) for large existing or new boilers (61). The implementation of these emission regulations for NO_x is still being studied at this time. Also the "bubble concept" is being considered whereby emission limits would be tied to the combined emission of SO_x and NO_x.

Some commercial experience in NO_x reductions through combustion modifications has been gained at some coal-fired plants in Sweden (58). Three 120 MW(t) coal-fired boilers that began operation in 1982 have comparatively large furnaces with tangential firing and overfire air injection. The NO_x emission is comparatively low, 0.14 g NO_2/MJ (400 mg/m^3). The extra cost is about 6 SK/kW(t), i.e. 16 SK/kW(e). Similar performance has been reported at other new pulverized coal-fired plants. Some retrofitted facilities include low-NO_x burners. The emissions of NO_x are in those cases 0.2-0.28 g NO_2/MJ (570-800 mg/m^3). Information about costs and operation experience is not yet available.

As of 1984 motor vehicles accounted for 70% of the total NO_x emission inventory, and hence, control of mobile NO_x emissions has become a major concern. In order to achieve widest possible international coordination of emission control requirements for motor vehicles and at the same time gain introduction of best commercial technology for emission control, the Swedish government has initiated a cooperation with seven other countries. This cooperation is known as the Stockholm group. The first objective of the work is to develop a Regulation for passenger cars that will serve as a basis for national legislation and mutual acceptance of approvals or certificates for automobiles. The emission requirements in the Regulation will be the same as the U.S. federal requirements for 1987 year models. In Sweden, these requirements are now introduced on a voluntary basis for 1987 and 1988 model years and will be compulsory for passenger cars beginning with the 1989 model year. Lead-free gasoline is now also being introduced at all filling stations in Sweden, and is generally available throughout Sweden. Lead-free gasoline is required to be supplied at all filling stations in the country (with the exception of stations with only one pump), as of July 1, 1987.

Lead-free gasoline is defined as fuel containing no more than 0.013 g of lead per liter at 15°C. The lead-free grade will have a Research octane number of 95 and will replace the present regular grade with an octane number of 93. Leaded gasoline may not contain more than 0.15 g of lead per liter. It will be sold in the form of a premium grade with an octane number of 98 and in the form of a medium grade which will consist of a mix of lead-free grade and the leaded premium grade. Approximately 25-30% of the cars in the present car population can be run on lead-free fuel. The consumption of lead-free gasoline will increase at the rate new cars designed to be driven on such fuel are added to the car fleet. The content of lead in gasoline is regulated under the Act on Chemical Products. The Petrol Ordinance contains the detailed provisions. By virtue of the Chemical Products Act there is thus a ban on the import and manufacture of leaded regular gasoline for use within Sweden as of January 1, 1986. The content of benzene in gasoline is also regulated under the Act on Chemical Products. The benzene content is limited to 5% by volume.

7.3.3 Fuel Oil Users Fee (58)

In order to achieve both a reduction of emissions and a reduction of oil consumption, a special fee is being charged to users of fuel oil. This surcharge finances a special fund, the Fuel Environment Fund. Subsidies for the construction of FGD plants or for emission-reduction measures of equal value are disbursed from this fund. The original purpose was to support arrangements to reduce sulfurous emissions from the combustion of coal. However, the scope of the fund has been widened beginning in 1986 to encompass measures to reduce NO_x emissions from combustion of coal as well as measures to reduce the environmental impact of the combustion of peat and waste. The Government contribution is limited to a maximum of 75% of the investment cost.

7.4 DENMARK

Electric utilities have over an eleven-year period converted to 95% use of coal fuel overall (62). 4,000 MW(e) of an overall generating capacity of 8,000 MW(e) will be equipped with twelve FGD systems by 1995. One 350 MW(e) dry-scrubbing-type FGD system under construction will achieve 92% SO_2 removal in typical low-sulfur coal service. Planning for reduction of NO_x emission inventory is underway.

7.5 NORWAY (63)

Because of the wide abundance of hydroelectric power there are presently no fossil fueled power plants in Norway. It is possible that one or two 600 MW(e) gas-fired power plants will be built within a time frame of about 10 years. Virtually sulfur free gas from the North Sea will be used and no FGD will thus be required.

FGD has been installed on industrial sources such as aluminum smelters, industrial oil-fired boilers, an ilmenite prereduction furnace and tail gas from Claus sulfur plants. A large FGD system is currently being supplied to a RCC-unit at an oil refinery. Nearly all of the FGD systems are Flakt-Hydro seawater scrubbers aggregating the equivalent of 1430 MW(e) scrubber capacity as described in Section 2.3.3. The control requirements for such large sources are set on a case by case basis in accordance with local requirements. The SO_2 emission from small industrial boilers, which are located in urban areas, is limited by burning low (1.2%) sulfur oil.

7.6 FINLAND

As outlined in Section 2.3.3, above, furnace limestone injection test work has been carried out beginning in 1984 leading to a 1986, full-scale, 250 MW(e) installation on low-sulfur bituminous coal service with limestone injected at the superheating level to avoid furnace slagging. It is equipped with a 125 MW(e) capacity, direct-contact, flue-gas humidifier that boosts SO_2 removal in gas it treats to 80%.

7.7 FRANCE

Due to the strong orientation toward nuclear power development in France, SO_2/NO_x emission reduction efforts are understood to be principally directed towards decreased fossil fuel usage.

In 1985, a parliamentary panel headed by Minister Valroff published a report presenting a proposed action plan for "acid rain" control (64). Elements of this plan tied to SO_2 and NO_x control consist of the following:

o In conjunction with a French government objective to gain a 50% reduction in the 1980 SO_2 emission inventory by 1990, which objective had already been reached in 1985, an SO_2 emission levy of 130 francs/metric ton of SO_2 is proposed, applicable to combustion sources larger than 50 MW(t) and to non-combustion sources greater than 2,500 metric tons of SO_2 per year, to help fund investments aimed at SO_2 emission reduction as well as related process development studies. Special emphasis for such funding goes to fluidized-bed combustion and to other processes allowing desulfurization.

o Implementation of "special protection zone" and "alarm zone" systems for specific areas, particularly the city of Strasbourg.

o Limiting of sulfur content of diesel fuel and distillate heating oil to 0.2% in conjunction with such a Europe-wide measure to be adopted by the European Economic Community (EEC).

o Studies of forest dieback.

o A speed limitation on motor vehicles in conjunction with actions by EEC.

Additional related recommendations include:

o A substantial action plan for reduction of hydrocarbon emissions to curb ozone formation considered to be of significance in forest dieback.

o Flue gas treating for urban waste incineration to collect hydrogen chloride.

7.8 BELGIUM

Like France, Belgium emphasizes use of nuclear power. However, although specific national laws requiring FGD do not presently exist, it is expected that a planned 600 MW(e) coal-fired boiler and an existing 300 MW(e) boiler being converted from blast furnace gas to coal will be required to have FGD at efficiency levels comparable to such system installations in West Germany.

7.9 SWITZERLAND

National SO_2 regulations are in place similar to those in West Germany, but there are no existing coal- or oil-fired boilers of substantial size.

In Switzerland, as in West Germany, the spreading decay of the forests is believed to demonstrate unequivocally, that atmospheric pollution in that country has reached proportions which seriously threaten the environment and, hence, human health (65).

A detailed overall survey of the nature/effect of emissions of atmospheric pollutants in Switzerland including the decay of forests, as regards the main harmful substances--sulfur dioxide (SO_2), nitrogen oxides (NO_x) and hydrocarbons (HC)--is being prepared. There has been a considerable increase in air pollution in Switzerland since the 1950s. Although SO_x emissions have tended to decline since the beginning of the 1970s, NO_x and HC emissions have continued their upward trend. Dendrochronological analyses indicate that the proportion of trees showing growth disorders has constantly risen since the 1950s and forestry experts believe that, to protect the forests, air pollution should be brought down to its 1950-1960 level. The Swiss Federal Council has adopted a series of measures seeking to accomplish this.

7.10 ITALY

In conjunction with extensive coal energy development in Italy major FGD activity is foreseen by U.S. system suppliers (66). In a new, cooperative, coal-logistics-related activity by the government of Italy and the U.S. Department of Energy (DOE) and a recent joint study effort, "Final Report on U.S.-Italian Coal Logistics" examines the present and future fuel requirements of Italian utilities and industries and the capability of meeting the requirements with U.S. coal (67). The U.S. DOE said Italy is converting many of its older power stations to coal and building new power plants. Because of that, the report says Italy could double its current steam coal consumption by the 1990s. Currently the U.S. supplies about nine million annual metric tons of coal to Italy, which is approximately 40% of the coal used in that country. While metallurgical coal use will remain relatively constant, steam coal demand is expected to sharply increase.

The government-owned national power company, ENEL, is building 10 MW(e) Wellman-Lord, limestone-gypsum, and ammonia-scrubbing demonstration FGD systems in Sardinia for service in high-sulfur bituminous coal. As outlined in Section 2.3.3, above, a bromine-liquor based regenerative FGD pilot plant will also be installed in Sardinia for operation in 1988 or 1989.

ENEL is reported to have recently announced planning and strategy for use of wet FGD in coal-fired boiler service and use of modified burners for NO_x emission control (68).

7.11 SPAIN

In conjunction with the new membership of Spain in the European Economic Community new stringent regulations for environmental protection are expected to take effect in a few years (69). Current SO_2 and NO_x control related technical development activity in that country includes:

- o Assessment in a Basque regional-government sponsored study of local dolomite and limestone sources for potential use in wet and/or dry FGD.
- o Coal study work to coordinate FGD process selection with characteristics of indigenous fuel.

Current tolerant national regulations (Decreto 833/1975, BOE-1975) limit SO_2 emissions from boilers to the level of 3,000 mg/Nm^3 for oil-firing, 2,400 mg/Nm^3 for bituminous or anthracite, and 9,000 mg/Nm^3 for lignite, and there is no significant experience with FGD. 20% of boiler supply is solid fuel.

7.12 UNITED KINGDOM

To the dismay of some other European countries, British authorities have in 1986 licensed a new/large, high-sulfur coal-fired unit in North Yorkshire without requiring SO_2 emission control (70).

However, two positive developments are reported (71):

- o The UK-government owned national power company, CEGB, in actively investigating the construction of two new coal-fired power plants within the next few years, is fully expected to utilize SO_2 controls.
- o The national government's Department of Trade and Industry has recently commissioned a comprehensive study of available treatment processes for SO_2 and NO_x control, a report on which is expected to be issued in the spring of 1987.

Reduced NO_x emissions in firing of oil and gas has become a major objective. The latest requirements are for 100 ppm NO_x on oil and 50 ppm NO_x on gas, with a total particulates limit of 115 mg/Nm^3. In newest jet-atomizing fuel-burner designs particulate levels of 50 mg/Nm^3 are being achieved while maintaining efficient oxygen levels, with NO_x levels approximately 150 ppm on oil and 80 ppm on gas for most radiant burners in standard configuration (72). By adding discrete external flue gas recirculation (FGR) into the burner these NOx levels can be brought down to and below the latest requirements, but extra ductwork and fans are required for conveying the flue gas. For this reason burners to achieve FGR internally by means of eduction and thereby eliminate extra hardware are being developed. The development of staged fuel or air burners is being avoided since it is felt that this would compromise overall combustion performance of liquid and gaseous fuel burners.

7.13 TURKEY (73)

Three small limestone FGD systems are being installed in Turkey.

7.14 OTHER COUNTRIES

Planning of FGD systems on very large SO_2 emission sources in the German Democratic Republic (East Germany) and Czechoslovakia has begun (35).

A Wellman-Lord FGD system has been purchased for a power plant in East Berlin (74).

In Yugoslavia, investigations are underway at two coal-fired power plants to determine the cost of installing FGD (74).

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